Coal *Works* for America

FOUNDATION COAL
HOLDINGS, INC.

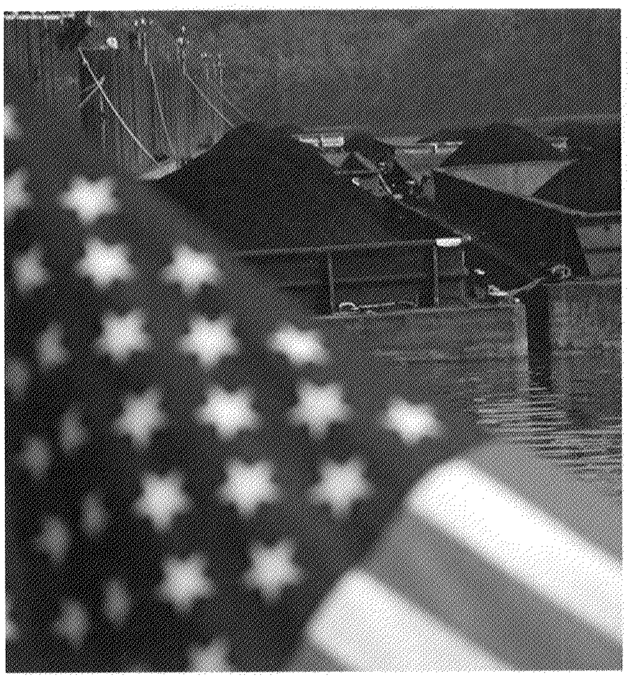
2008 ANNUAL REPORT

Coal is the engine that drives our economy...

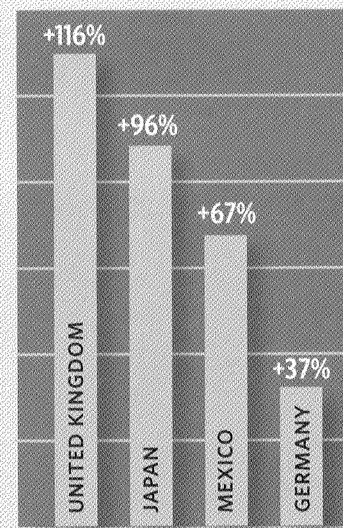
...and puts our people to work.

Coal lowers our electricity costs

When it comes to inexpensive electricity, coal is king. Powering almost 50 percent of electrical generation in America, coal-fired electricity is far cheaper than electricity generated from other major sources. Over time the cost of electricity generated from coal has been approximately one-third the cost of electricity from natural gas, and one-fourth the cost of electricity derived from petroleum.*



Other Countries' Costs of Industrial Electricity Compared to the U.S., 2007



Source: International Energy Agency, "Key World Energy Statistics," 07

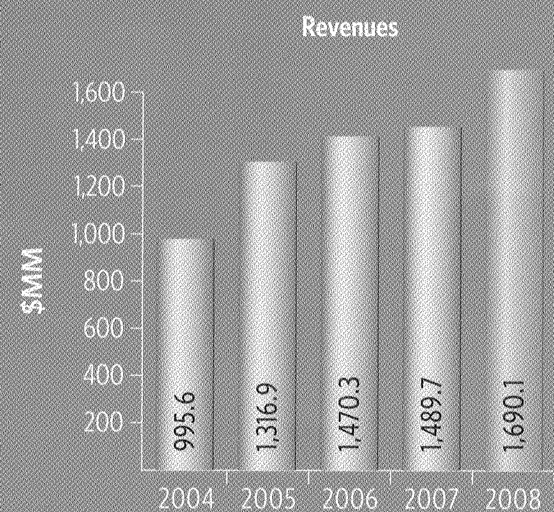
Lower costs mean more jobs

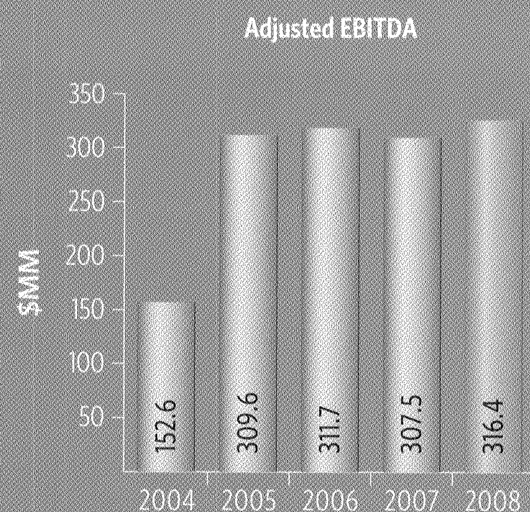
Abundant domestic coal helps keep our electricity costs low compared to many of our international competitors, which in turn reduces production costs for American goods and services. So factories that might otherwise relocate abroad can afford to stay home, creating American jobs.

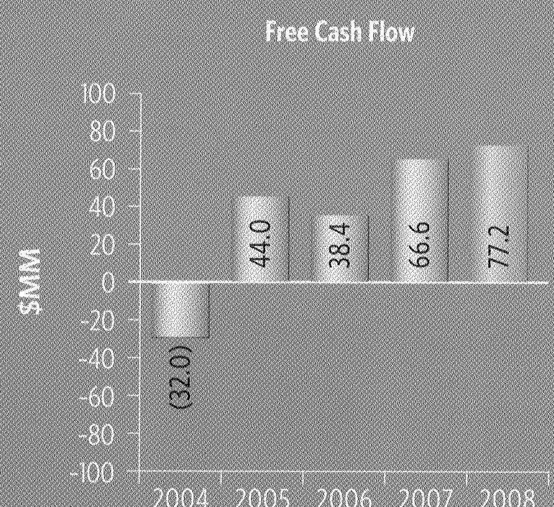
At Foundation Coal Holdings, Inc. and its affiliates, we're proud to be one of the nation's leading producers of our most economical, most abundant source of energy. In this report, we'll show you why coal works for America—and why Foundation Coal works as a smart investment in America's future.

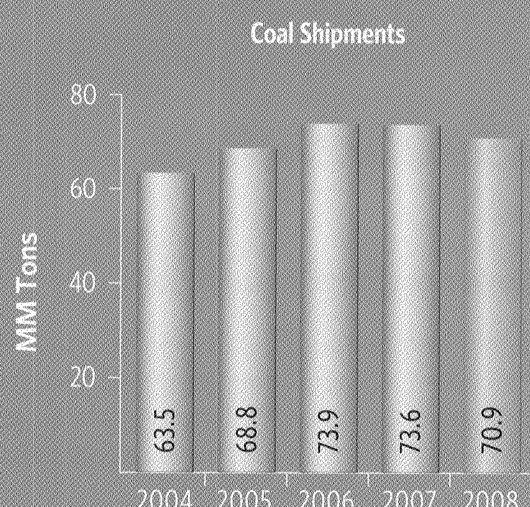
*Energy Information Administration, 2008

Our 2008 financial highlights include...





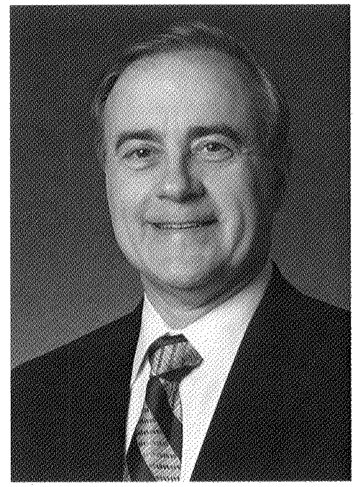




...new records in revenues, adjusted EBITDA and free cash flow.

COAL WORKS FOR AMERICA

JAMES F. ROBERTS,
Chairman and CEO



Fellow Shareholders:

The year 2008 was certainly one to remember in the coal industry. The industry experienced unparalleled price swings for coal, building rapidly from the beginning of the year to record high prices by around mid-year and then retreating quickly in the face of a severe global economic downturn. To a large degree, we anticipated the upswing in the global demand for coal that drove the price hikes, and we positioned the company for record annual performance on a number of critical financial measures for 2008 and into the future. What now appears to be a prolonged global economic deceleration presents challenges that will require us to react quickly and continually improve our operations to meet our goal to provide exceptional value for our shareholders.

2008 Financial Highlights

The graphs on the facing page highlight the company's performance over a five-year period on several measures:

- Revenues grew to a record $1.69 billion, with higher per ton sales realizations in all regions where the company operates.
- Adjusted EBITDA grew to a record $316.4 billion and the company anticipates that 2009 also will produce record adjusted EBITDA.
- Free cash flow grew to a record $77.2 million, which equates to $1.68 per share.
- Coal shipments declined modestly during the year. The company continues to be the only company with major coal production in both the Eastern coal fields of Pennsylvania and West Virginia and in the Powder River Basin of Wyoming.

Strategic Accomplishments

In last year's annual report to shareholders, we listed four specific strategic initiatives that we felt were critical to the company's future growth and shareholder value creation. Each is presented below with a brief description of progress toward completion:

1. **Maximize current assets through organic growth.** Installing the second longwall at the Emerald Mine drove fourth quarter Northern Appalachian coal shipments to a record 4.1 million tons in our highest margin production region.

2. **Advance the permitting process for new mines.** The permitting process normally requires two to four years for a small mine and five years or longer for a larger operation. Foundation Coal remains on track for permitting the Freeport Mine, an expansion mine in Northern Appalachia capable of producing both metallurgical and steam coal, and the Foundation Mine, which will have the capacity to sustain Northern Appalachian longwall production for years into the future.

We positioned the company for record annual performance on a number of critical financial measures for 2008 and into the future.

3. **Increase reserves in the Powder River Basin.** Early in 2008, Foundation Coal successfully bid on 224 million additional tons of reserves for the Eagle Butte Mine in the Powder River Basin. During 2010 the company expects to bid on substantial additional reserves for the Belle Ayr Mine.

4. **Focus on the development of land and gas resources.** Foundation successfully operated its coal gas recovery business in 2008 and will continue to grow this business in 2009 and beyond. Coal gas recovery processes methane extracted from the coal seam and sells it to the natural gas marketplace, creating a valuable commodity and enhancing shareholder value.

Beyond the specific initiatives listed above, Foundation Coal places intense focus on safety at all its operations. We believe that each employee has a right to a safe workplace. We want each employee to return home after each workday injury free. Our employees are committed to doing their jobs safely and efficiently. Foundation Coal and its affiliates are recognized industry leaders in mine safety. In 2008 Foundation Coal finished the year with the best safety performance in its history, a 27 percent improvement over 2007.

Coal Market Outlook

Long-term fundamentals for the coal industry remain quite positive. Future demand for coal is expected to continue to grow both in the U.S. and around the world. International demand is projected to expand by more than 45 percent between now and 2030, according to the Energy Information Administration, with the most substantial growth to come from rapid expansion of electrical power generation in China and India. In the U.S. alone, 19 gigawatts of new coal-fired electricity will come on-line by 2012, which will contribute to a substantial increase in annual coal consumption.

Early in 2008, increased domestic demand for U.S. coal along with global supply interruptions tightened the markets, causing prices to spike for both thermal and metallurgical coal. We sold most of our coal for 2009 while prices were in these upper ranges, which positioned us very well for the coming year.

Subsequently, during the fourth quarter of 2008, prices began to retreat rapidly as the economic slowdown intensified. Looking forward, we expect markets in 2010 will return to a relative balance of supply and demand as production from high-cost mines is reduced and the global economic situation improves.

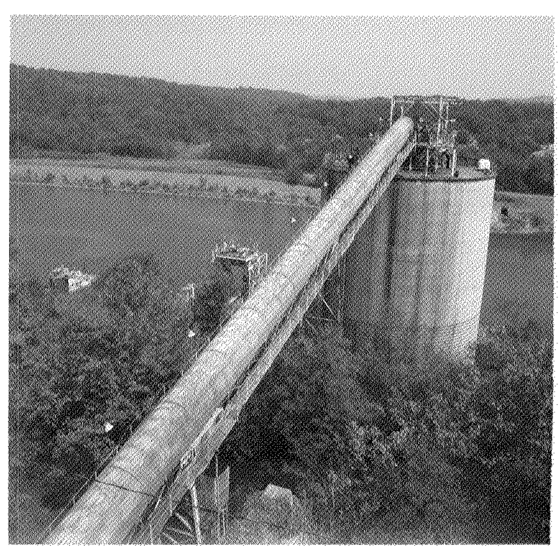
Value Proposition

Foundation Coal is well positioned to continue to provide exceptional value to its shareholders even in difficult economic times. We are a low-cost coal producer with a strong liquidity position. We produce coal safely and in an environmentally responsible way from a large and geographically diverse base of reserves. The U.S. and the world economies need to expand all sources of energy. Coal will remain central to meeting America's energy needs and ensuring the continued leadership of the U.S. in the global economy. All of which leads me to conclude that "Coal works for America."

Sincerely,

James F. Roberts

James F. Roberts
Chairman and CEO



COAL WORKS FOR AMERICA

KURT D. KOST,
President, COO and CEO Designate

Fellow Shareholders:

Most of you already know that Jim Roberts, Chairman and CEO of Foundation Coal, recently announced his retirement effective at the end of June 2009. As part of the company's succession plan, he will relinquish his CEO responsibilities and will become Executive Chairman on July 1, 2009. On that date, I will assume the CEO responsibilities. During his tenure as the chief executive officer, he and Foundation's management team successfully guided the company through its initial public offering and established Foundation Coal as one of the premier coal producers in the nation. Plus, Jim has been active nationally in promoting the coal industry as safe, environmentally-friendly and a key component in America's energy future, both through his work within Foundation Coal and through his actions as the former Chairman of the National Mining Association.

Looking ahead, I expect that Foundation will continue to build on its successes. In my future role as CEO, and with the help of our outstanding management team, I plan to ensure that Foundation remains one of America's leading coal producers, maintains its high standards for safety, operations, product quality, and customer satisfaction, and ensure that Foundation Coal continues to grow shareholder value.

2008 Operational Highlights

Foundation Coal produced a number of important operational milestones in 2008 that are listed below:

Received Safety Awards. Several of Foundation Coal affiliate mines received safety awards in 2008, including: the Laurel Creek Mine #5 and the Paynter Branch Mine, each of which earned the Mountaineer Guardian safety award at the 35th West Virginia Coal Mining annual symposium; and Kingston Mines (No. 1 and No. 2) and the Rockspring Mine received the Joseph A. Holmes safety award at the 25th annual meeting of the West Virginia State Council. These awards recognize efforts made by employees to work safely and contribute to our focus on building a culture of safety in all of our operations.

Achieved Record Quarterly Northern Appalachian Shipments. The fourth quarter produced record coal shipments of 4.1 million tons, as both the Cumberland and Emerald Mines recorded very strong performances. The increased shipments helped drive costs per ton down by 43 percent, compared with the prior quarter.

Increased per ton sales realizations. For 2008 average per ton sales realization increased in each operating region over the previous year. Sound sales and marketing strategies and superior execution are expected to continue to drive revenue growth with average per ton realizations again increasing in 2009.

Based on its forward sales position, its low-cost operations, and its strong liquidity position, Foundation Coal expects to achieve record production and financial performance in 2009.

Received Environmental Awards. The Belle Ayr Mine received the Director's Award from the U.S. Office of Surface Mining and Reclamation and the Wyoming Department of Environmental Quality's reclamation award. Foundation Coal has a strong history of reclamation that has restored land to its original or improved land uses.

2009 Strategic Initiatives

In order to continue to deliver strong operational performance in 2009, Foundation Coal will focus on the following strategic initiatives:

Maintain high standards of safety and regulatory performance. The company understands that keeping its employees safe and meeting or exceeding regulatory requirements is directly linked to business success.

Deliver quality products and services to customers. Coal is a relationship business, where repeat customers value products that consistently meet critical specifications and expect service that is timely and reliable.

Reduce controllable costs and capital expenditures. Foundation Coal will keep its mines well capitalized to ensure efficient operations, but it also intends to carefully review all capital spending requirements, drive down unnecessary costs and preserve cash to support its strong liquidity position. Foundation produces 95 percent of its coal from low-cost mines.

Innovate productivity improvements through the involvement and input of employees. The management of Foundation Coal strives to establish and maintain a culture of trust throughout the company. By treating each other with dignity and respect, employees are empowered to manage their work, be accountable for successes and mistakes, and work together to make continual improvements. Open discussions that employ sound leadership principles produce decisions that improve operations at all levels. The company has strong employee involvement programs in place and expects to utilize and expand them.

Selectively pursue growth through acquisition. Foundation Coal will continue to evaluate opportunities to grow the company through M&A activity, carefully weighing considerations of valuation, transaction feasibility, potential synergies and culture to achieve our strategic goals and add value to our shareholders.

Long-term Outlook

While the long-term global prospects for coal remain positive, the business environment may prove challenging in the short-term. The effect of economic stimulus responses to the economic downturn, initiated by the governments of the U.S. and other countries, have yet to be fully realized. Elements of the U.S. economic stimulus package could affect coal production and pricing. The proposed additional funding for advanced clean coal technologies is promising.

When breakthrough technologies for the capture and storage of carbon dioxide are commercially deployed and demonstrated to be effective, coal-fired electricity will strengthen its leading role in new electricity generation both in the United States and, perhaps more importantly, around the globe—especially in regions that desperately need a secure and plentiful source of affordable electricity.

Risks remain if the downturn continues for an extended period of time. Residential, commercial and industrial demand for electricity could grow more slowly than expected or even contract. In this environment, coal companies with low-cost production and superior execution will still deliver value to shareholders.

Overall, we believe that Foundation Coal's highly hedged forward sales position, its low-cost operations and its strong liquidity position have combined to lay the groundwork for record financial performance in 2009 and make Foundation one of the best positioned domestic producers in today's market environment. In this respect, not only does "Coal Work for America," but as a Foundation Coal shareholder, "Coal Works for You."

Sincerely,

Kurt D. Kost
President and COO

OUR MANAGEMENT TEAM

BACK ROW, LEFT TO RIGHT:
JAMES J. BRYJA, Senior Vice President, Operations
A. SCOTT PACK, JR., Senior Vice President, Sales and Marketing and President, Foundation Energy Sales, Inc.
TODD ALLEN, Vice President, Investor and Media Relations
JAMES A. OLSEN, Senior Vice President, Chief Information Officer
MICHAEL R. PEELISH, Senior Vice President, Safety and Human Resources
FRANK J. WOOD, Senior Vice President, Chief Financial Officer

FRONT ROW, LEFT TO RIGHT:
JAMES F. ROBERTS, Chairman of the Board of Directors and Chief Executive Officer
GREG A. WALKER, Senior Vice President, General Counsel and Secretary
KURT D. KOST, President, Chief Operating Officer and Chief Executive Officer Designate

COAL WORKS FOR AMERICA'S ECONOMY

Following a challenging 2008 for American businesses, a solid recovery depends upon our ability to jump start the economy. The availability of inexpensive electrical power from coal will prove critical to the nation's success.

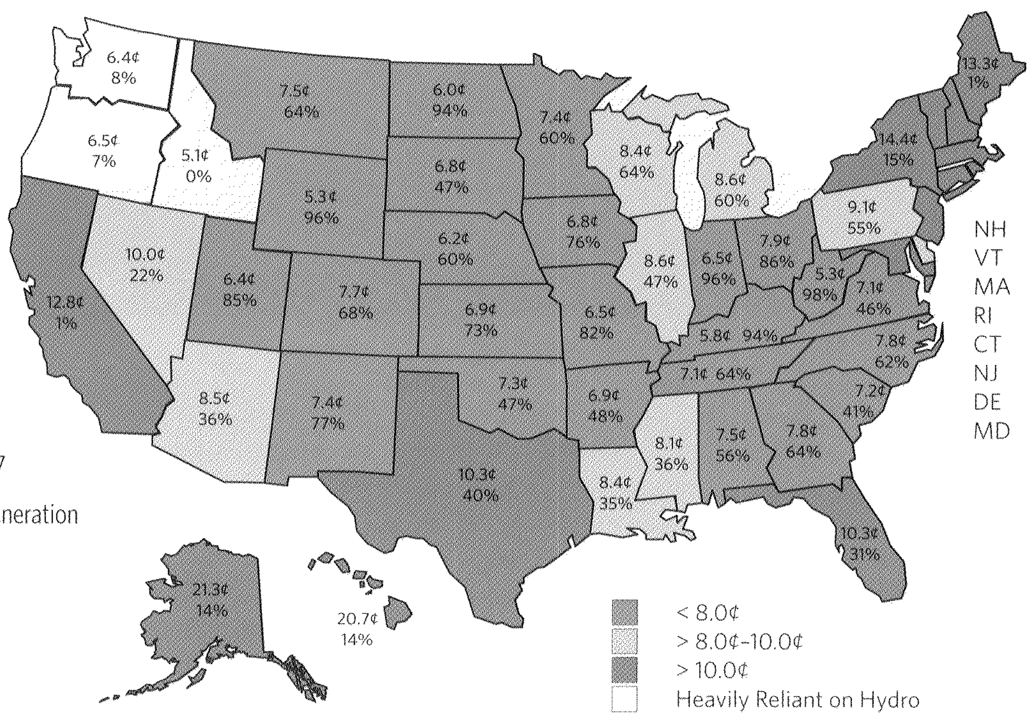
Low energy bills reduce a company's cost of doing business, which leaves more money to hire new employees, to invest in new technologies, and to bring new products to market. America has a tremendous advantage in this energy race, because our nation holds an astonishing 29 percent of the world's coal supply—more than any other country on earth!

Electricity is more affordable wherever coal is used

As the map below demonstrates, coal is the single most important factor in reducing electricity costs in the U.S. today. Excluding the Pacific Northwest, which is fortunate enough to have abundant hydro-power, the states with the most inexpensive electricity tend to get the majority of their power from coal. *The 24 lowest-cost states (marked in green) produce on average 70 percent of electricity from coal, while the 23 highest-cost states (in gray and blue) use coal for less than 30 percent of their electricity generation.*

Coal is the key to producing low-cost electricity

Cost per KWh & percentage of coal-based electrical power



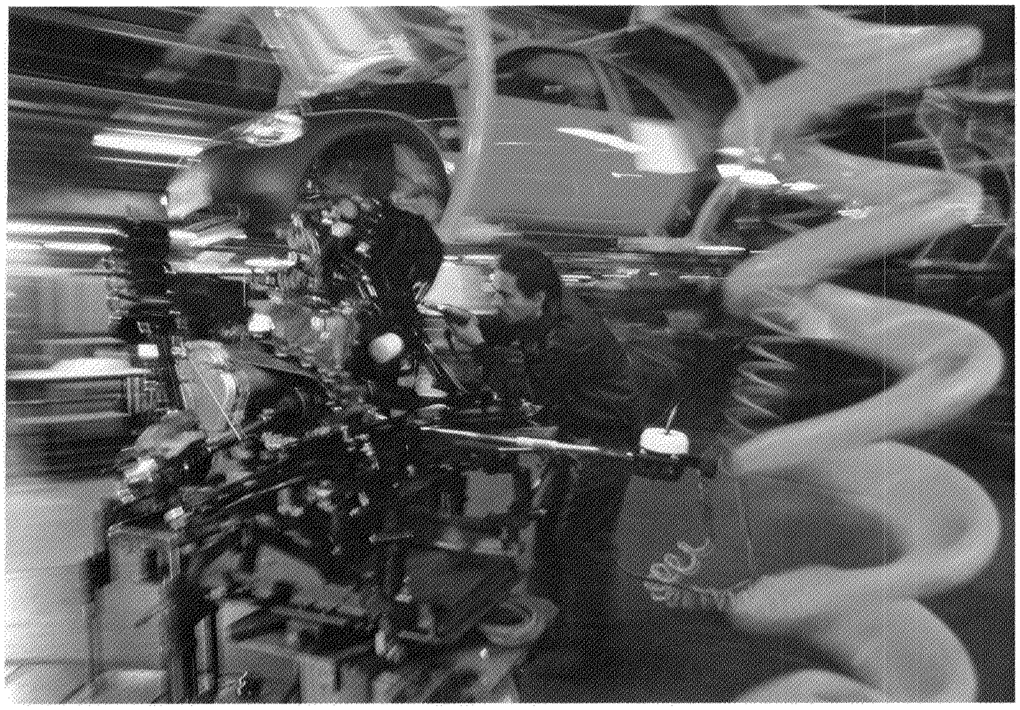
NH	14.0¢	17%
VT	12.0¢	0%
MA	15.2¢	25%
RI	13.2¢	0%
CT	16.2¢	11%
NJ	11.9¢	17%
DE	11.4¢	74%
MD	11.4¢	60%

¢ = average retail price per kilowatt hour, 2007

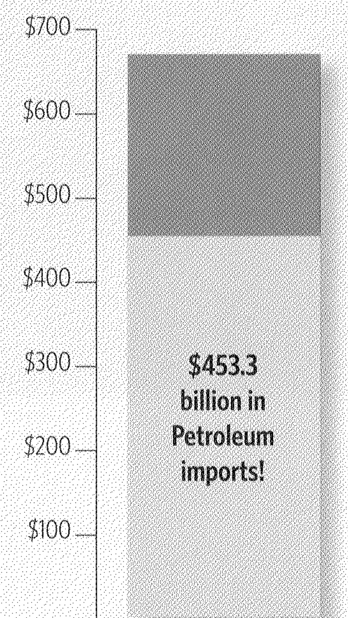
% = percent of total generation from coal, 2007

[3] Energy Information Administration, 2008

Moreover, the areas of the country that are most dependent upon low energy costs for business—like the industrial heartland and the food-producing states of the great plains—depend upon coal for the majority of their electrical needs, as they have for generations.



A worrisome percentage of our burgeoning trade deficit is caused by petroleum imports. With the help of strong leadership from Washington and proven coal-to-liquids technology, we could substantially reduce our dependence on foreign oil and keep billions of dollars at home, producing American power and building the American economy.

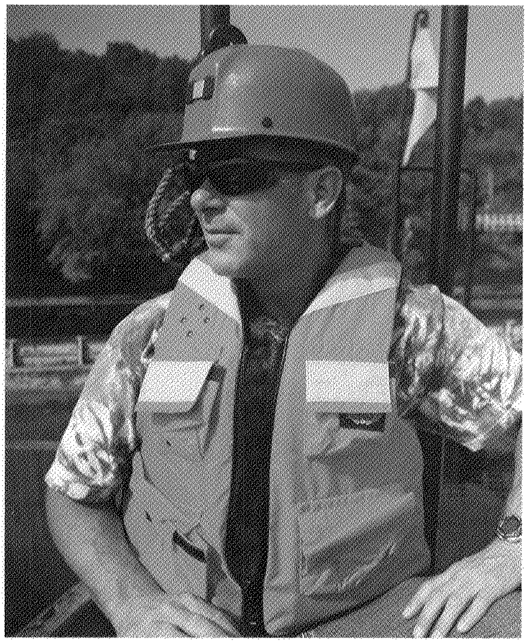


U.S. Trade Deficit 2008
$677.1 billion

U.S. Department of Commerce

Reducing a company's electrical costs can be just as effective as a tax break in stimulating growth—but at no cost to the American taxpayer.

COAL WORKS FOR AMERICAN JOBS



Rather than shipping our dollars overseas to buy petroleum and natural gas, we can use those dollars to fund American jobs and American industries. According to the National Mining Association, the coal industry directly employs more than 120,000 people; and the association estimates that for each coal mining job another 3.5 jobs are created elsewhere in linked industries, from electric generating plants to transportation companies that move raw materials.

The ripple effect

But direct employment in coal and coal-related industries is just a small part of the story. Electricity is a $200 billion per year commodity in the United States—our nation's single biggest commodity. A landmark 2006 study by two researchers at Penn State University explored the potential impact of restricting coal use by displacing it with higher cost energy sources. If we replaced just one-third of coal-fired electricity with a mix of natural gas, nuclear and renewables by 2015, the resulting surge in U.S. electricity costs would result in 1.2 million job losses and a $166 billion decline in economic output. That number more than doubles if we displace two-thirds of our coal-fired electricity.

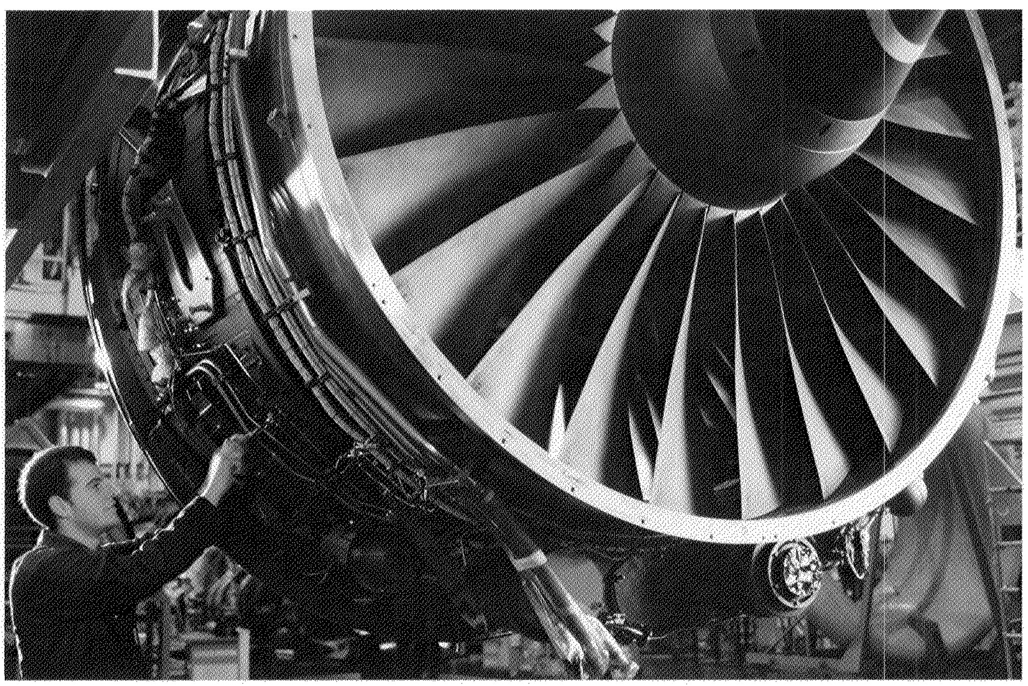
According to the study, the benefits of keeping coal as a key component of electricity generation will benefit every state in the study. Even California would gain $58 billion in increased output through 2015 by maintaining the import of 20 percent of its electricity from coal-fired plants in other western states.

Net Costs of Replacing Coal in the Continental U.S. Through 2015

	33% of coal replaced	66% of coal replaced
Loss in Economic Output	$166 billion	$371 billion
Loss in U.S. Jobs	1.2 million	2.8 million

Source: Economic Impacts of Coal Utilization and Displacement in the Continental U.S. (July 2006)

Independent energy consultants forecast that every one percent increase in electricity costs will result in a loss of 20,000 to 40,000 jobs. The impact is clear: coal keeps America at work.

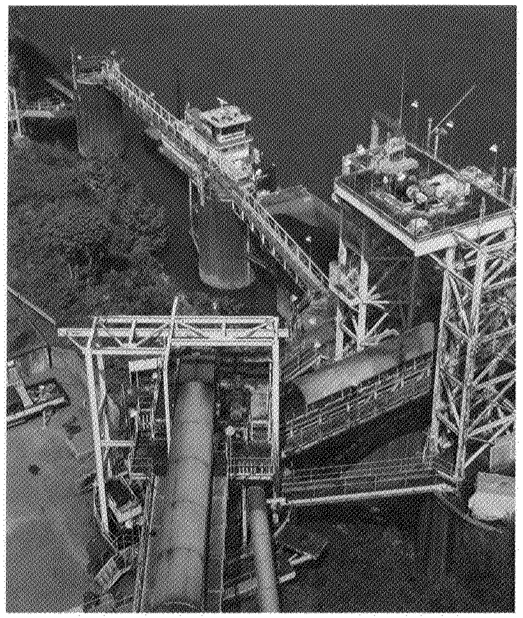


Average Wages for Mining Versus Average for U.S. Workers

Source: National Mining Association

A bright spot in America's economy

The mining industry was one of the few industry sectors to post job gains in 2008, which is a testament to the ability of coal to act as the financial foundation for hundreds of communities, even in the most difficult times. What's more, jobs in the mining industry are high-paying—over 50 percent more than the average wage for all U.S. workers.



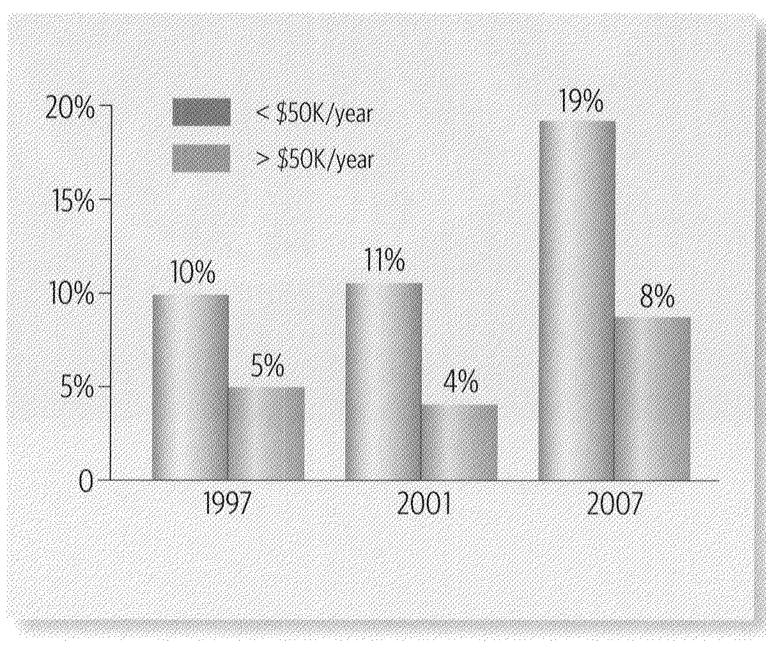
COAL WORKS FOR AMERICAN FAMILIES

The dramatic spike in energy prices that occurred in mid-2008 served as a foreshadowing of the future that awaits America's families if we ignore the need for energy independence in America. Last summer world demand for gasoline brought prices to over $4 per gallon, lifting the cost of other energy sources. The strain on family budgets was dramatic and undeniable.

The upward trend

But in reality, this brief spike in prices underscores a trend that has been in place for decades: energy costs have been rising far faster than inflation, taking an ever larger bite from the average family's wallet. For families making less than $50,000 per year, energy costs as a share of after-tax income nearly doubled in the decade from 1997 to 2007. That represents a massive decline in disposable income that families might otherwise spend on goods and services that improve their quality of life. In fact, rising energy prices are a big reason why so many middle class families feel that they just can't get ahead in today's economy.

Family Energy Costs as a Percentage of After-Tax Income



Source: U.S. Energy Information Administration, Surveys of Residential Energy Consumption (97 and 01) and Short Term Energy Outlook (Nov. 07)

How to increase family earning power

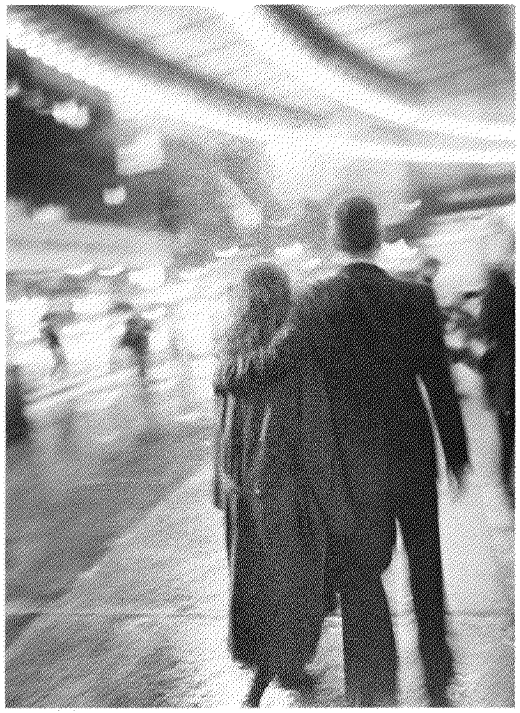
A commitment to coal can help reverse this trend. By building a new generation of clean-burning coal-fired electrical plants and by making a commitment to the proven technologies that turn coal into clean-burning transportation fuel, we can begin to exert a much higher level of control over energy supplies and energy prices in this country. And, abundant domestic coal gives us the power to do it.

The products we buy, the lives we lead, the future we hope for, all can cost less if our nation makes a commitment to abundant, affordable coal.

Coal means more to families than just electricity

Contrary to popular belief, coal is one of our most efficiently used natural resources. Coal by-products are integral parts of items we use every day. Here's a partial list of products made with coal that are part of our everyday lives:

Asphalt
Bricks
Cement
Dyes
Insecticides
Nylon
Paint
Perfumes
Pharmaceuticals
Photo developer
Plastics
Roof shingles
Snow/Ice Control Products
Synthetic Rubber
Solvents
Steel
Vitamins
Wallboard
...and much more!



COAL WORKS FOR AMERICA'S FUTURE

The future of American energy lies with clean coal—a concept that, while derided by some, is in reality a proven, decades-long movement that has already created stunning successes—and is poised for more.

Remember acid rain? Starting in the 1970s, new technologies from the clean coal movement reduced emissions of sulfur dioxide and nitrogen oxide by as much as 90 percent. Thanks to clean coal initiatives, acid rain is well controlled in the U.S.

New challenges to face

Today, the clean coal movement is focused on a range of new issues. We're working on enhanced scrubbing and filtering processes, greater production efficiencies, and above all, carbon capture and storage techniques. The coal-based electricity sector is spending more than $500 million on clean coal initiatives, and with the recent stimulus bill adding $3.4 billion to fund advanced clean coal technology projects, we are confident that more breakthroughs will occur.

Is it working? Yes it is.

The U.S. Department of Energy reports that coal plants utilizing advanced coal combustion technologies achieve a 30–40 percent improvement in operating efficiency compared to plants using pulverized coal technology, which translates into a nearly equivalent reduction in CO2 emissions. And current carbon capture and storage research projects are proving that, while hurdles remain, the promise of clean coal is within our grasp.

> "We need...to put clean coal technology on the fast track, and that means money. It means investment in research."
> —Barack Obama

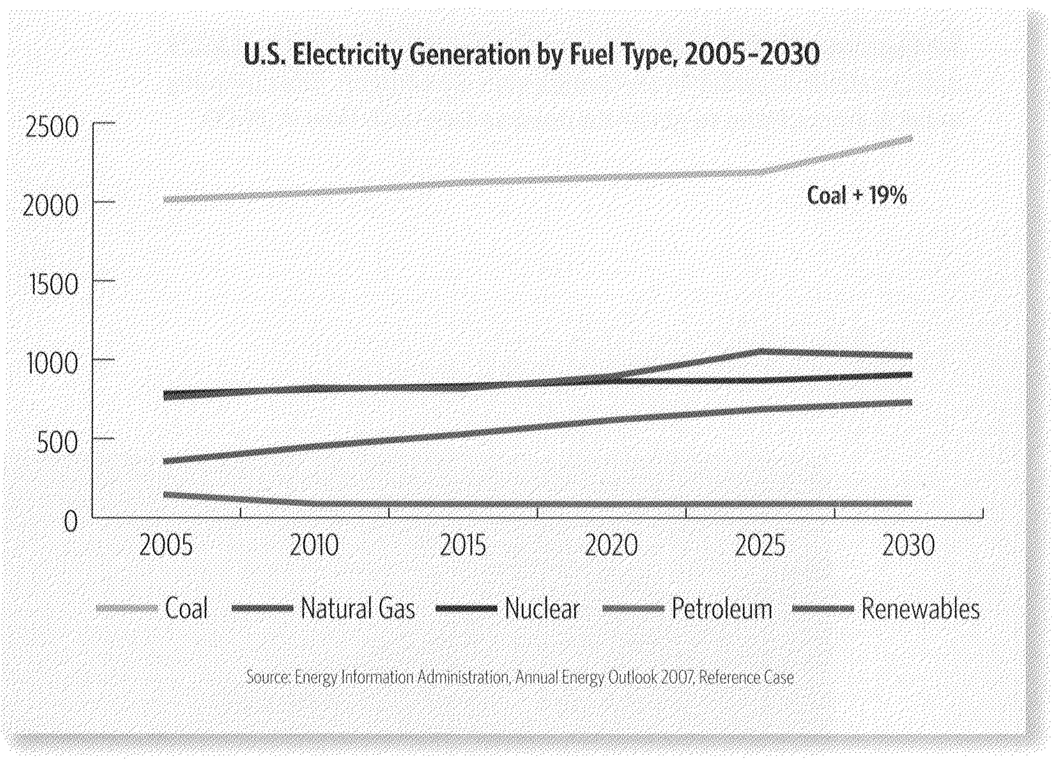
Clean Coal can be a high-tech industry

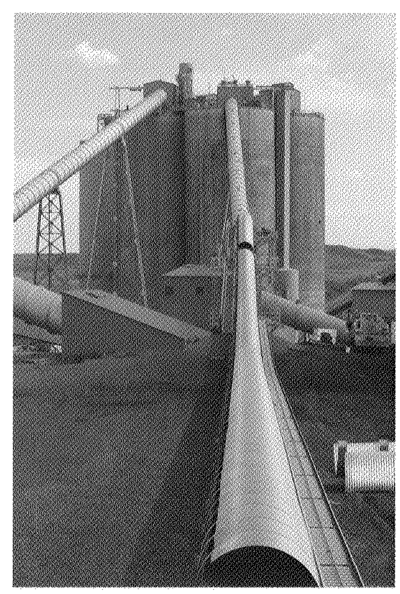
At Foundation Coal, we favor a multi-pronged approach to addressing America's energy needs, including nuclear, renewables, clean coal technologies, and conservation and energy efficiency. In addition to making our nation more secure, this balanced approach helps keep electricity rates affordable. Global demand for power generating technologies and services will create a $480 billion export market over the next three decades, and will support more than 600,000 high-quality jobs. Becoming world leaders in clean coal technologies will mean more jobs for Americans, and a more secure energy future for America.

Coal-fired electricity generation to increase 19 percent from 2005 to 2030

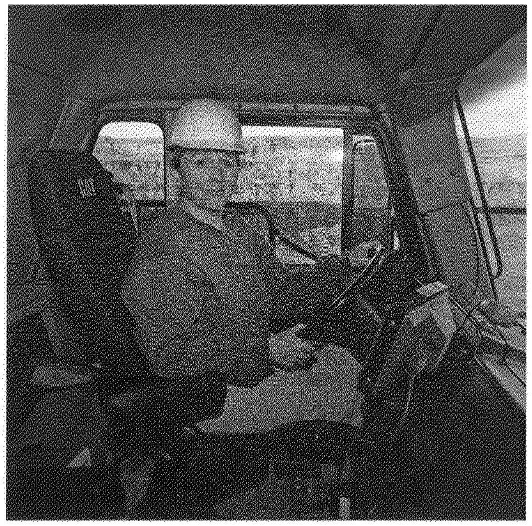
The simple fact is, the world will need coal for decades to come. No other energy source—not nuclear, not solar, not wind, not biomass—can possibly meet the sheer volume of the world's energy demand. So our future lies with coal—and our obligation, to ourselves and our children, is to make coal an ever more environmentally friendly source of power.

With coal-fired plants in the pipeline that represent more than 25,000MW of new electricity, the U.S. is experiencing the largest expansion of coal-fired generation in 25 years.





FOUNDATION COAL WORKS FOR SHAREHOLDERS



Low-Cost Operator—Foundation Coal operates some of the lowest cost mines in the country.

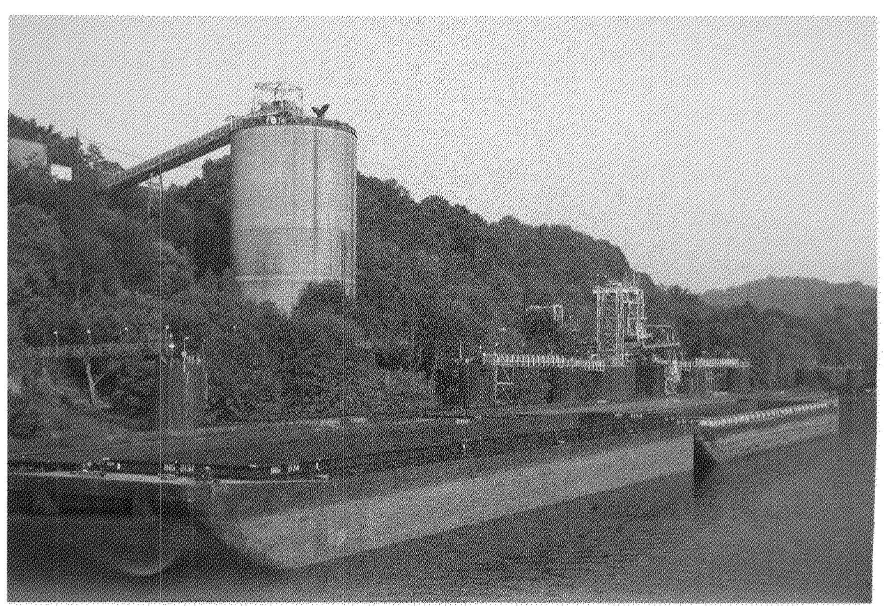
- Wyoming—Two large surface mines produce coal from the lowest cost region in the U.S.
- Pennsylvania—Two large longwall mines consistently produce high per-ton margins based on the low cost of production and the premier prices received for high BTU coal.
- West Virginia—Approximately half of our Central Appalachian production comes from our largest underground mine in West Virginia, which competes favorably with the lowest cost mines in the region.

Favorable 2009 Contract Prices—At the end of the third quarter, the company had sold 94 percent of its expected 2009 production at higher average prices than received in 2008.

Diversity of Coal Products—Foundation Coal affiliates operate mines in Central Appalachia, Northern Appalachia and the Powder River Basin of Wyoming, providing an extensive portfolio of different coal products.

Strong Liquidity Position—At year-end, Foundation Coal had $329 million available under its revolving credit agreement. The company expects to continue to generate positive free cash flow in 2009.

Foundation Coal is well positioned in 2009 and expects to deliver record financial performance. And as energy prices rebound, Foundation Coal is positioned to prosper well into the future.



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SEC
Mail Processing
Section

APR 07 2009

Washington, DC
122

FORM 10-K
FOR ANNUAL AND TRANSITION REPORTS PURSUANT TO SECTIONS 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

(Mark One)

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

For the Fiscal Year Ended December 31, 2008

or

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

For the Transition Period From to

Commission File Number 001-32331

Foundation Coal Holdings, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State or Other Jurisdiction of Incorporation or Organization)**	**42-1638663** **(I.R.S. Employer Identification No.)**
999 Corporate Boulevard, Suite 300 **Linthicum Heights, Maryland** **(Address of Principal Executive Offices)**	**21090** **(Zip Code)**

Registrant's telephone number, including area code (410) 689-7500

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	New York Stock Exchange

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

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

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 ☐ No ☑

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the Registrant's voting and non-voting common equity held by non-affiliates of the Registrant calculated using the June 30, 2008 closing price on the New York Stock Exchange, was $3,956 million. There were 44,564,987 shares of common stock outstanding on February 24, 2009.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's definitive Proxy Statement submitted to the Registrant's stockholders in connection with our 2009 Annual Stockholders Meeting to be held on May 13, 2009, are incorporated by reference into Part III of this report. The definitive proxy statement shall be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are not statements of historical fact and may involve a number of risks and uncertainties. These statements relate to analyses and other information that are based on forecasts of future results and estimates of amounts not yet determinable. These statements may also relate to our future prospects, developments and business strategies.

We have used the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project" and similar terms and phrases, including references to assumptions, in this Annual Report on Form 10-K to identify forward-looking statements. These forward-looking statements are made based on expectations and beliefs concerning future events affecting us and are subject to uncertainties and factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control, that could cause our actual results to differ materially from those matters expressed in or implied by these forward-looking statements. The following factors are among those that may cause actual results to differ materially from our forward-looking statements:

- market demand for coal, electricity and steel;
- future economic or capital market conditions;
- weather conditions or catastrophic weather-related damage;
- our ability to produce coal at existing and planned future operations;
- the consummation of financing, acquisition or disposition transactions and the effect thereof on our business;
- our plans and objectives for future operations and expansion or consolidation;
- our relationships with, and other conditions affecting, our customers;
- timing of reductions or increases in customer coal inventories;
- long-term coal supply arrangements;
- risks in coal mining;
- environmental laws, including those directly affecting our coal mining and production, and those affecting our customers' coal usage;
- competition;
- railroad, barge, trucking and other transportation performance and costs;
- our assumptions concerning economically recoverable mineral reserve estimates;
- employee workforce factors;
- regulatory and court decisions;
- future legislation and changes in regulations or governmental policies or changes in interpretations thereof;
- changes in postretirement benefit and pension obligations;
- our liquidity, results of operations and financial condition;
- disruptions in delivery or changes in pricing from third party vendors of goods and services which are necessary for our operations, such as fuel, steel products, explosives and tires; and
- other factors, including those discussed in "Risk Factors" "ITEM 1A."

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

PART I

To aid readers unfamiliar with the terms commonly used in the coal industry, a glossary of selected terms is provided at the end of "ITEM 1. BUSINESS."

Unless the context otherwise indicates, as used in this Annual Report on Form 10-K ("10-K") the terms "the Company" "we" "our" "us" and similar terms refer to Foundation Coal Holdings, Inc. and its consolidated subsidiaries.

ITEM 1. BUSINESS.

Overview

We are the fourth largest coal producer in the United States, based on tons produced. We operate a diverse group of twelve individual coal mines located in Wyoming, Pennsylvania and West Virginia. For the year ended December 31, 2008, we sold 70.9 million tons of coal, including 69.3 million tons that were produced and processed at our operations. As of December 31, 2008, we had approximately 1.7 billion tons of proven and probable coal reserves. We are also involved in marketing coal produced by others to supplement our own production and, through blending, provide our customers with coal qualities beyond those available from our own production.

We are primarily a supplier of steam coal to U.S. utilities for use in generating electricity. We also sell steam coal to industrial plants. Steam coal sales accounted for 98% of our coal sales volume and 89% of our coal sales revenue in 2008. We also sell metallurgical coal to steel producers; metallurgical sales accounted for 2% of our coal sales volume and 11% of our coal sales revenue in 2008.

As of January 26, 2009, we had a total sales backlog of over 259 million tons of coal, and our coal supply agreements have remaining terms ranging from less than one year to 13 years. For 2008, we sold approximately 86% of our sales volume under long-term coal supply agreements. We consider sales commitments with a duration longer than twelve months as a "long-term" contract as opposed to spot sales agreements with a duration of twelve months or less. As of January 26, 2009, we had sales and price commitments for approximately 97% of our planned 2009 shipments, approximately 59% of our planned 2010 shipments, and approximately 29% of our planned 2011 shipments.

Competitive Strengths

We believe that the following competitive strengths enhance our prominent market position in the United States:

We are the fourth largest coal producer based on tons produced in the United States and have significant coal reserves. Based on 2008 production of 69.4 million tons, we are the fourth largest coal producer in the United States. As of December 31, 2008, we controlled approximately 1.7 billion tons of proven and probable coal reserves. Based on these reserve estimates and our actual rate of production during the year ended December 31, 2008, we have a total reserve life of approximately 25 years.

We have a diverse portfolio of coal mining operations and reserves. We operate a total of twelve mines in the Powder River Basin, Northern Appalachia and Central Appalachia, selling coal to dozens of domestic and foreign electric utilities, steel producers and industrial users. We are the only producer with significant operations and major reserve blocks in both the Powder River Basin and Northern Appalachia, two U.S. coal production regions for which future demand is expected to increase. We believe that this geographic diversity provides us with a significant competitive advantage, allowing us to source coal from multiple regions to meet the needs of our customers and reduce their transportation costs.

We operate highly productive mines and have had strong EBITDA margins. We believe our focus on productivity has helped contribute to our strong EBITDA margins for fiscal years ended 2006, 2007 and 2008. Our strategic investment in equipment and technology has increased the efficiency of our operations, which we believe reduces our costs and provides us with a competitive advantage. Maintaining our low-cost position enables us to maximize our profitability in all coal pricing environments.

We are a recognized industry leader in safety and environmental performance. Our focus on safety and environmental performance results in a lower likelihood of disruption of production at our mines, which leads to higher productivity and improved financial performance. We operate some of the nation's safest mines, with 2008 total injury incident rates, as tracked by the Mine Safety and Health Administration ("MSHA"), below industry averages.

We have long-standing relationships and long-term contracts with many of the largest coal-burning utilities in the United States. We supply coal to numerous power plants operated by a diverse group of electricity generators across the country. We believe we have a reputation for reliability and superior customer service that has enabled us to solidify our customer relationships.

Our management team has a track record of success during our long operating history. Our management team has a proven record of generating free cash flow, increasing productivity, reducing costs, developing and maintaining long-standing customer relationships and effectively positioning us for future growth and profitability. We operated as a stand-alone subsidiary of privately held RAG Coal International AG from 1999 until becoming an independent company on July 30, 2004. Our senior executives have an average of approximately 28 years of experience in the coal industry, including an average of 19 years of experience operating our assets when owned by us and our predecessors.

Business Strategy

Our objective is to increase shareholder value through sustained earnings and cash flow growth. Our key strategies to achieve this objective are described below:

Maintaining our commitment to operational excellence as a low-cost producer. We seek to maintain our productivity leadership with an emphasis on lowering costs by continuing to invest selectively in new equipment and advanced technologies, such as our previous investments in underground diesel equipment, increased longwall face widths and a larger shield system. We will continue to focus on profitability and efficiency by leveraging our significant economies of scale, large fleet of mining equipment, information technology systems and coordinated purchasing and land management functions. In addition, we continue to focus on productivity through our culture of workforce involvement by leveraging our strong base of experienced, well-trained employees.

Capitalizing on industry dynamics through a balanced approach to selling our coal. Despite the near term weakness in coal prices, the long term fundamentals of the U.S. coal market are favorable. We employ a balanced approach to selling our coal, including the use of long-term sales commitments for a portion of our future production while maintaining uncommitted planned production to capitalize on favorable future pricing environments.

Selectively expanding our production and reserves. Given our broad scope of operations and expertise in mining in major coal-producing regions in the United States, we believe that we are well-situated to capitalize on the expected continued growth in U.S. and international coal consumption by evaluating growth opportunities, including (i) expansion of production capacity at our existing mining operations, (ii) further development of existing significant reserve blocks in Northern Appalachia and Central Appalachia, and (iii) potential strategic acquisition opportunities that arise in the United States or internationally. We will prudently act to expand our reserves when appropriate. For example, we increased our reserve position by obtaining mining rights to federal coal reserves adjoining our current operations in Wyoming through the Lease By Application ("LBA") process.

Continuing to provide a mix of coal types and qualities to satisfy our customers' needs. By having operations and reserves in three major coal producing regions, we are able to source coal from multiple mines to meet the needs of our domestic and international customers. Our broad geographic scope and mix of coal qualities provide us with the opportunity to work with many leading electricity generators, steel companies and other industrial customers across the country.

Continuing to focus on excellence in safety and environmental stewardship. We intend to maintain our recognized leadership in operating some of the safest mines in the United States and in achieving environmental excellence. Our ability to minimize workplace incidents and environmental violations improves our operating efficiency, which directly improves our cost structure and financial performance.

History

Amoco Minerals Company was incorporated in Delaware on September 2, 1969, as a subsidiary of Amoco Corporation. The name was changed to Cyprus Minerals Company on May 24, 1985 and then spun-off from Amoco Corporation in July of 1985.

Cyprus Minerals Company merged with and into AMAX, Inc., a New York corporation, on November 15, 1993, with Cyprus Minerals Company being the surviving corporation under the name Cyprus Amax Minerals Company. The combined coal mining businesses were consolidated under Cyprus Amax Coal Company at the time of the 1993 merger.

On June 30, 1999, Cyprus Amax Minerals Company and its subsidiary, Amax Energy Inc., sold the stock of Cyprus Amax Coal Company and all of its subsidiaries consisting of its remaining coal properties to RAG International Mining GmbH (renamed RAG Coal International AG ("RAG")). After the closing of this transaction in 1999, our parent holding company was RAG American Coal Holding, Inc.

Foundation Coal Holdings, LLC was formed on February 9, 2004, by a group of investors for the purpose of acquiring the United States coal properties owned by RAG. A stock purchase agreement was signed on May 24, 2004.

Foundation Coal Holdings, LLC, through its subsidiary, Foundation Coal Corporation, and pursuant to the stock purchase agreement, completed the acquisition of 100% of the outstanding common shares of RAG American Coal Holding, Inc. and its subsidiaries from RAG, on July 30, 2004 (the "Transaction").

Foundation Coal Holdings, LLC, merged on August 17, 2004 into its subsidiary, Foundation Coal Holdings, Inc., a Delaware corporation that was formed on July 19, 2004. Foundation Coal Holdings, Inc. was the surviving entity in this merger. On December 9, 2004, we completed the initial public offering (the "IPO") of Foundation Coal Holdings, Inc.

On September 19, 2005, Foundation Coal Holdings, Inc. completed a secondary offering and partial exercise of the over-allotment shares in which its sponsors, First Reserve IX, L.P. ("First Reserve"), The Blackstone Group ("Blackstone") and AMCI III, LLC sold an aggregate of 10,260,500 shares of common stock. Foundation Coal Holdings, Inc. did not sell any shares of common stock through this offering, nor did Foundation Coal Holdings, Inc. receive any proceeds from the sale.

On January 24, 2006, all of the remaining shares of common stock of Foundation Coal Holdings, Inc. were distributed by affiliates of our sponsors, Blackstone and First Reserve, to their limited and other partners.

Coal Mining Techniques

We use four different mining techniques to extract coal from the ground: longwall mining, room-and-pillar mining, truck-and-shovel mining and truck and front-end loader mining.

Longwall Mining

We utilize longwall mining techniques at our Cumberland and Emerald mines in Pennsylvania. Longwall mining is the most productive and safest underground mining method used in the United States. A rotating drum is trammed mechanically across the face of coal, and a hydraulic system supports the roof of the mine while the drum advances through the coal. Chain conveyors then move the loosened coal to a standard underground mine conveyor system for delivery to the surface. Continuous miners are used to develop access to long rectangular blocks of coal which are then mined with longwall equipment, allowing controlled subsidence behind the advancing machinery. Longwall mining is highly productive and most effective for large blocks of medium to thick coal seams. High capital costs associated with longwall mining demand large, contiguous reserves. Ultimate seam recovery of in-place reserves using longwall mining is much higher than the room-and-pillar mining underground technique. All of the raw coal mined at our longwall mines is washed in preparation plants to remove rock and impurities.

Room-and-Pillar Mining

Our Kingston, Laurel Creek and Rockspring mines in West Virginia utilize room-and-pillar mining methods. In this type of mining, main airways and transportation entries are developed and maintained while remote-controlled continuous miners extract coal from so-called rooms by removing coal from the seam, leaving pillars to support the roof. Shuttle cars and battery coal haulers are used to transport coal to the conveyor belt for transport to the surface. This method is more flexible and often used to mine smaller coal blocks or thin seams. Ultimate seam recovery of in-place reserves is typically less than that achieved with longwall mining. All of this production is also washed in preparation plants before it becomes saleable clean coal.

Truck-and-Shovel Mining and Truck and Front-End Loader Mining

We utilize truck-and-shovel mining methods in both of our mines in the Powder River Basin. We utilize the truck and front-end loader method at our surface mines in West Virginia (the "Pioneer mines"). These methods are similar and involve using large, electric or hydraulic-powered shovels or diesel-powered front-end loaders to remove earth and rock (overburden) covering a coal seam which is later used to refill the excavated coal pits after the coal is removed. The loading equipment places the coal into haul trucks for transportation to a preparation plant or loadout area. Ultimate seam recovery of in-place reserves on average exceeds 90%. This surface-mined coal rarely needs to be cleaned in a preparation plant before sale. Productivity depends on overburden and coal thickness (strip ratio), equipment utilized and geologic factors.

Business Environment

Coal is an abundant, efficient and affordable natural resource used primarily to provide fuel for the generation of electric power. World-wide economically recoverable coal reserves using today's technology are estimated to be approximately 930 billion tons. The United States is one of the world's largest producers of coal and has approximately 28% of global coal reserves, representing nearly 250 years of supply based on current usage rates. According to the U.S. Department of Energy, the energy content of the United States coal reserves exceeds that of all the known oil supplies in the world.

Coal Markets. Coal is primarily consumed by utilities to generate electricity. It is also used by steel companies to make steel products and by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. In general, coal is characterized by end use as either steam coal or metallurgical coal. Steam coal is used by electricity generators and by industrial facilities to produce steam, electricity or both. Metallurgical coal is refined into coke, which is used in the production of steel. Over the past quarter century, total annual coal consumption in the United States (excluding exports) has nearly doubled to approximately 1.2 billion tons in 2008. The growth in the demand for coal has coincided with an increased demand for coal from electric power generators.

Consumption by Sector	Actual[1] 2005	2006	2007	Preliminary[2] 2008	Projected[1] 2015	2030	Annual Growth 2008-2015	2015-2030
				(Tons in millions)				
Electric Generation	1,037	1,027	1,046	1,041	1,095	1,210	1 %	1 %
Industrial	60	59	56	55	56	57	-	-
Steel Production	24	23	23	23	20	18	(2)%	(1)%
Coal-to-Liquids Processes	-	-	-	-	17	70	-	10 %
Residential/Commercial	4	3	3	4	3	3	(3)%	-
Export	50	50	59	81	65	44	(3)%	(3)%
Total	1,175	1,162	1,187	1,204	1,256	1,402	1 %	1 %

[1] Actual and projected data estimates are based on data published in the EIA's Annual Energy Outlook 2009.

[2] Preliminary data based on the EIA's Short Term Energy Outlook 2009.

Much of the nation's power generation infrastructure is coal-fired. As a result, coal has consistently maintained a 49% to 53% market share during the past 10 years, principally because of its relatively low cost, reliability and abundance. Coal is the lowest cost fossil fuel used for base-load electric power generation, being considerably less expensive than natural gas or oil. Coal-fired generation is also competitive with nuclear power generation especially on a total cost per megawatt-hour basis. The production of electricity from existing hydroelectric facilities is inexpensive, but its application is limited both by geography and susceptibility to seasonal and climatic conditions. Through 2008, non-hydropower renewable power generation accounted for only 2.1% of all the electricity generated in the United States, and wind and solar power represented only 1.1% of United States power generation.

Coal consumption patterns are also influenced by the demand for electricity, governmental regulation impacting power generation, technological developments, transportation costs, and the location, availability and cost of other fuels such as natural gas, nuclear and hydroelectric power.

Coal's primary advantages are its relatively low cost and availability compared to other fuels used to generate electricity. Using 2007 Federal Energy Regulatory Commission Form 1, Energy Information Administration ("EIA") 412, EIA-906/923 and RUS-12 filings as a basis, Ventyx, a commonly used authoritative resource for industry commodity pricing, has estimated the average total production costs of electricity, using coal and competing generation alternatives in 2008, as follows:

Electrical Generation Type	Cost per Megawatt Hour
Petroleum	$ 102.75
Natural Gas	$ 73.95
Non-hydro renewables*	$ 69.45
Coal	$ 24.64
Hydroelectric	$ 19.74
Nuclear	$ 17.62

* Includes: electricity generation from solar, wind, agriculture byproducts, biomass, geothermal, landfill gas, wood waste and other waste products.

Coal Production. United States coal production was approximately 1.2 billion tons in 2008. The following table, derived from data prepared by the EIA, sets forth production statistics in each of the major coal producing regions for the periods indicated.

	Actual[1]			Preliminary[2]	Projected[2]		Annual Growth	
Production by Region	**2005**	**2006**	**2007**	**2008**	**2015**	**2030**	**2007-2015**	**2015-2030**
				(Tons in millions)				
Powder River Basin	430	472	479	494	533	551	1 %	-
Central Appalachia	236	236	226	230	170	140	(4)%	(1)%
Northern Appalachia	140	136	132	143	158	184	1 %	1 %
Illinois Basin	96	95	96	93	131	172	5 %	2 %
Other	229	224	213	208	215	288	-	2 %
Total	1,131	1,163	1,146	1,168	1,207	1,335	-	1 %

(1) Actual data estimates are based on coal production information published in the EIA's coal production website.

(2) Preliminary and projected data per EIA Annual Energy Outlook 2009.

Coal Regions. Coal is mined from coal fields throughout the United States, with the major production centers located in the Western United States, Northern and Central Appalachia and the Illinois Basin. The quality of coal varies by region. Physical and chemical characteristics of coal are very important in measuring quality and determining the best end use of particular coal types.

Competition. The coal industry is intensely competitive. The most important factors on which we compete are coal price at the mine, coal quality and characteristics, transportation costs from the mine to the customer and the reliability of supply. Demand for coal and the prices that we will be able to obtain for our coal are closely linked to coal consumption patterns of the domestic electric generation industry, which are influenced by factors beyond our control. Some of these factors include the demand for electricity, which is significantly dependent upon economic activity and summer and winter temperatures in the United States, government regulation, technological developments and the location, availability, quality and price of competing sources of coal, alternative fuels such as natural gas, oil and nuclear, and alternative energy sources such as hydroelectric power.

Transportation Cost. Coal used for domestic consumption is generally sold free on board at the mine, and the purchaser normally bears the transportation costs. Export coal, however, is usually sold at the loading port, and coal producers are responsible for shipment to the export coal-loading facility, with the buyer responsible for further transportation.

Transportation costs are important to coal mining companies because the purchaser may choose a supplier largely based on cost of transportation. According to the National Mining Association ("NMA"), railroads account for nearly two-thirds of total United States coal shipments, while river barge movements account for an additional 20%. Trucks and overland conveyors haul coal over shorter distances, while barges, Great Lake carriers and ocean vessels move coal to markets served by water. Most coal mines are served by a single rail company, but some are served by two competing rail carriers. Rail competition is important because rail costs can constitute up to 75% of the delivered cost of coal in certain markets.

Coal Characteristics

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

Heat Value

The heat value of coal is commonly measured in British thermal units, or "Btus." A Btu is the amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit. Coal found in the eastern and Midwestern regions of the United States tends to have a higher heat value than coal found in the western United States.

Bituminous coal has a heat value that ranges from 10,500 to 14,000 Btu/lb. This coal is located primarily in our mines in Northern and Central Appalachia and in the Illinois Basin. Bituminous coal is used for utility and industrial steam purposes, and includes metallurgical coal, a feed stock for coke, which is used in steel production.

Sub-bituminous coal has a heat value that ranges from 7,800 to 9,500 Btu/lb. Our sub-bituminous reserves are located in Wyoming. Sub-bituminous coal is used almost exclusively by electric utilities and some industrial consumers.

Sulfur Content

Sulfur content can vary from seam to seam and sometimes within each seam. When coal is burned, it produces sulfur dioxide, the amount of which varies depending on the chemical composition and the concentration of sulfur in the coal. Compliance coal is coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus and complies with the requirements of the Clean Air Act. Low sulfur coal is coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btus.

Most of our sub-bituminous coal typically has a lower sulfur content than bituminous coal, but some of our bituminous coal in West Virginia also has a low sulfur content.

High sulfur coal can be burned in plants equipped with sulfur-reduction technology, such as scrubbers, which can reduce sulfur dioxide emissions. Plants without scrubbers can burn high sulfur coal by blending it with lower sulfur coal, or by purchasing emission allowances on the open market, which permit the user to emit a ton of sulfur dioxide per allowance. Additional scrubbing will provide new market opportunities for our noncompliance coals. All new coal-fired generation plants built in the United States are expected to use some type of clean coal-burning technology.

Operations

As of December 31, 2008, we operated a total of twelve mines located in Wyoming, Pennsylvania and West Virginia. We currently own most of the equipment utilized in our mining operations.

The following table provides summary information regarding our principal mining complexes as of December 31, 2008:

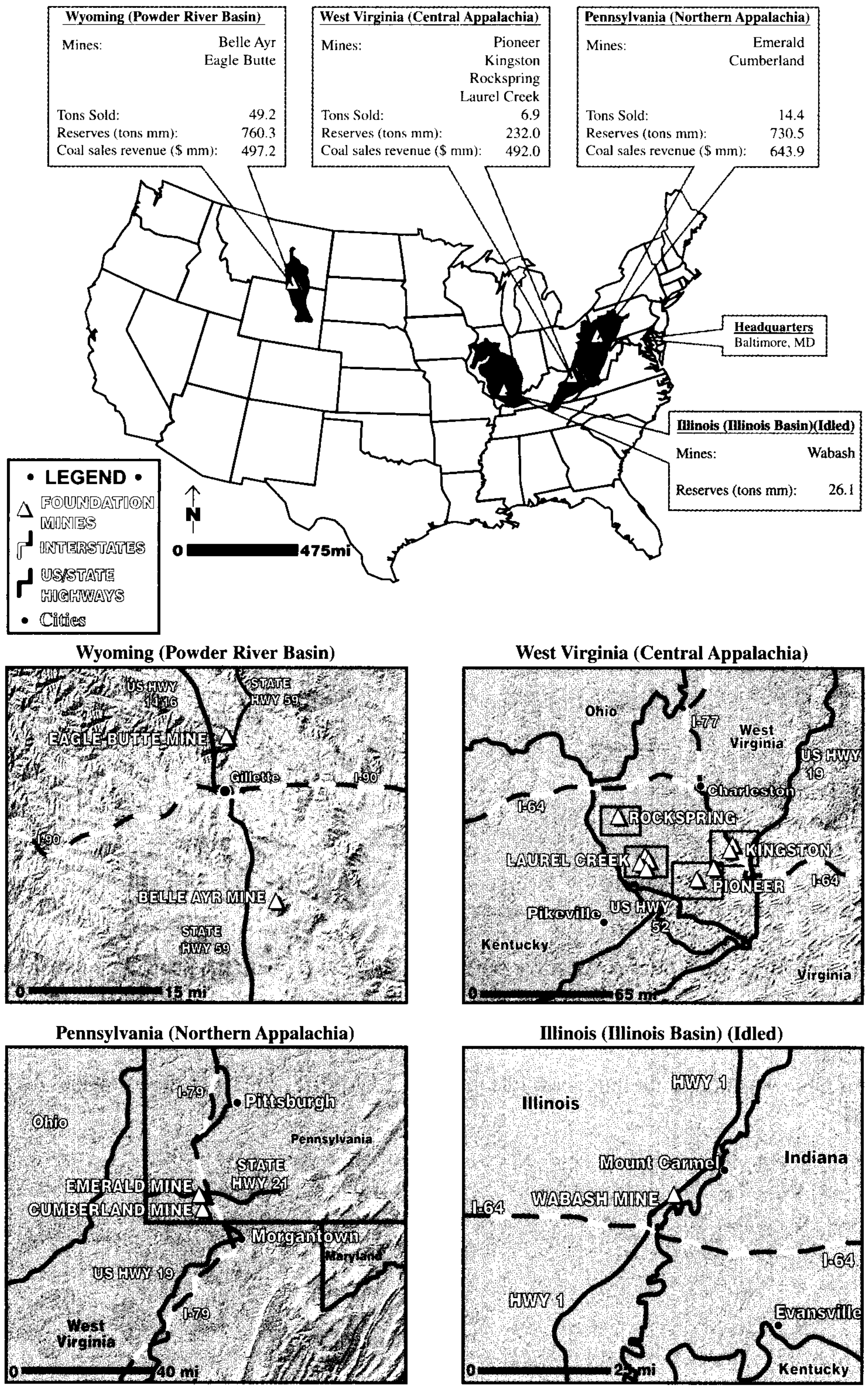
Mining Complex	Number of Mines	Type of Mine	Mining Technology	Transportation	Tons Produced in 2008 (In millions)	Tons Sold[1] in 2008 (In millions)
Wyoming						
Belle Ayr	1	Surface	Truck-and-Shovel	BNSF, UP	28.7	28.8
Eagle Butte	1	Surface	Truck-and-Shovel	BNSF, Truck	20.5	20.4
Pennsylvania						
Cumberland	1	Underground	Longwall	Barge, Truck	7.3	7.4
Emerald	1	Underground	Longwall	CSX, NS, Truck	6.4	6.2
Purchased and resold coal					-	0.8
West Virginia						
Kingston	2	Underground	Room-and-Pillar	Barge, CSX, NS	1.0	1.1
Laurel Creek	3	Underground	Room-and-Pillar	Barge, CSX	1.0	1.0
Rockspring	1	Underground	Room-and-Pillar	NS, Truck	3.0	2.9
Pioneer	2	Surface	Truck and Front-End Loader	Barge, NS, CSX/RJCC	1.5	1.5
Purchased and resold coal	-				-	0.4
Other						
Purchased and resold coal	-				-	0.4
Wabash mine[2]	-				-	-
Total	12				69.4	70.9

BNSF = BNSF Railway
CSX = CSX Transportation
RJCC = R.J. Corman Railroad Company
NS = Norfolk Southern Railway Company
UP = Union Pacific Railroad Company

[1] The tonnage shown for each mine, except for purchased and resold coal represents coal mined, processed and shipped from our active operations. Kingston and Pioneer tons sold include a total of 1.4 million tons of metallurgical coal. The tonnage shown in Other and labeled purchased and resold includes 0.1 million tons of metallurgical coal.

[2] The Wabash mine was placed on long term idle status as of April 4, 2007 and therefore had no tons produced or sold in 2008.

The following map outlines our operations, coal sales revenue, tons sold and reserves as of December 31, 2008:



The following provides a description of the operating characteristics of the principal mines and reserves of each of our mining operations.

Wyoming Operations

We control approximately 760.3 million tons of coal reserves in the Powder River Basin, the largest and fastest growing U.S. coal-producing region. Our subsidiaries, Foundation Coal West, Inc. and Foundation Wyoming Land Company, own and manage two sub-bituminous, low sulfur, non-union surface mines that sold 49.2 million tons of coal in 2008, or 71% of our total production volume. The two mines employ approximately 620 salaried and hourly employees. Our Powder River Basin mines have produced over one billion tons of coal since 1972.

Belle Ayr Mine

The Belle Ayr mine, located approximately 18 miles southeast of Gillette, Wyoming, extracts coal from the Wyodak-Anderson Seam, which averages 75 feet thick, using the truck-and-shovel mining method. Belle Ayr shipped 28.8 million tons of coal in 2008. The mine sells 100% of raw coal mined and no washing is necessary. Belle Ayr has approximately 255.6 million tons of reserves. Based on 2008 production levels, the reserves at Belle Ayr will sustain projected production for approximately 9 years if market conditions warrant. We plan to apply to lease several hundred million tons of surface mineable, unleased federal coal that adjoins Belle Ayr's property under the LBA process. If we prevail in the bidding process and obtain these leases, we will be able to extend the life of the mine. Belle Ayr has the advantage of shipping its coal on both of the major western railroads, the BNSF Railway and the Union Pacific Railroad.

Eagle Butte Mine

The Eagle Butte mine, located approximately eight miles north of Gillette, Wyoming, extracts coal from the Roland and Smith Seams, which total 100 feet thick, using the truck-and-shovel mining method. Eagle Butte shipped 20.4 million tons of coal in 2008. The mine sells 100% of the raw coal mined and no washing is necessary. On February 20, 2008, our affiliate successfully bid on a new federal coal lease adjacent to the western boundary of the Eagle Butte mine, containing approximately 224.0 million tons of proven and probable reserves. The lease became effective on May 1, 2008. Eagle Butte has approximately 504.7 million tons of reserves. Based on 2008 production levels, the reserves at Eagle Butte will sustain production levels for approximately 25 years if market conditions warrant. Coal from Eagle Butte is shipped on the BNSF Railway to power plants located throughout the West, Midwest and the South. The mine also ships a small portion by truck.

Pennsylvania Operations

We control approximately 730.5 million tons of contiguous reserves in Northern Appalachia. Approximately 161.5 million tons are assigned to active mines and 81.8 million tons are assigned to other permitted mines for future development. Approximately 487.2 million tons are unassigned. Our Pennsylvania affiliates' mines are located in the southwestern part of the state, approximately 60 miles south of Pittsburgh. Both mines operate in the Pittsburgh No. 8 Seam, the dominant coal-producing seam in the region, which is six to eight feet thick on these properties. The Pennsylvania operations consist of the Cumberland and the Emerald mining complexes, which collectively shipped 14.4 million tons in 2008, primarily using longwall mining systems supported by continuous mining methods. The mines sell high Btu, medium sulfur coal primarily to eastern utilities. The two mines employ approximately 1,420 salaried and hourly employees. The hourly work force at each mine is represented by the United Mine Workers of America ("UMWA").

Cumberland Mine

The Cumberland mining complex, located approximately 12 miles south of Waynesburg, Pennsylvania, was established in 1977. Cumberland shipped 7.4 million tons of coal in 2008. As of December 31, 2008, Cumberland had assigned reserves of 100.6 million tons. All of the coal at Cumberland is processed through a preparation plant before being loaded onto Cumberland's owned and operated railroad for transportation to the Monongahela River dock site. At the dock site, coal is then loaded into barges for transportation to river-served utilities or to other docks for subsequent rail shipment to non-river-served utilities. The mine can also ship a portion of its production via truck.

Emerald Mine

The Emerald mining complex, located approximately two miles south of Waynesburg, Pennsylvania, was established in 1977. As of December 31, 2008, Emerald had assigned reserves of approximately 60.9 million tons. Emerald shipped 7.0 million tons of coal in 2008 which included 0.8 million tons of purchased and resold coal. Emerald has the ability to store clean coal and blend variable sulfur products to meet customer requirements. All of Emerald's coal is processed through a preparation plant before being loaded into unit trains operated by the Norfolk Southern Railway or CSX Transportation. The mine also has the option to ship a portion of its coal by truck.

West Virginia Operations

Our subsidiaries operate four mining facilities located in West Virginia in the Central Appalachia region: Kingston, Laurel Creek, Rockspring and Pioneer. The Kingston, Laurel Creek and Rockspring facilities are all underground mining complexes that use room-and-pillar mining technology to develop and extract coal. The Pioneer mines operate two surface mines utilizing truck/loader systems to extract coal from multiple seams. Our West Virginia operations have approximately 87.6 million tons of reserves that are assigned to current or planned future operations and approximately 144.4 million tons of reserves that are unassigned and are being held for future development. Except for the two surface mines, all of the raw coal is processed through preparation plants before transportation to market. Production from the mines is typically low sulfur, high Btu coal. In 2008, our West Virginia affiliates' mines collectively shipped 6.9 million tons of coal which included 0.4 million tons of purchased and resold coal. These mines ship coal by rail, primarily via either the Norfolk Southern Railway or CSX Transportation, or by barge on the Kanawha and Big Sandy Rivers. These operations serve a diversified customer base, including regional and national customers. We also own and operate the Rivereagle loading facility on the Big Sandy River in Boyd County, Kentucky.

As of December 31, 2008, our West Virginia operations had approximately 1,000 non-union salaried and hourly employees. In November 2003, a UMWA election was held at the Rockspring mining facility, the outcome of which is pending. If the UMWA was properly elected, approximately 305 employees at the Rockspring facility would become represented by UMWA members. See ITEM 1A. RISK FACTORS for additional disclosure related to this matter.

Kingston Mines

The Kingston complex consists of two mines, Kingston #1 and Kingston #2, located in Fayette County and Raleigh County, respectively. Kingston #1 mines the Glen Alum Seam and Kingston #2 mines the Douglas Seam. In 2008, the Kingston complex shipped 1.1 million tons and as of December 31, 2008 had approximately 10.4 million tons of reserves of which approximately 7.2 million tons are assigned and approximately 3.2 million tons are unassigned and are being held for future development. Kingston sells coal primarily into the metallurgical market for domestic steel plants. The coal is trucked to the Kanawha River for shipment by barge or to CSX Transportation or the Norfolk Southern Railway loadouts for shipment by rail.

Laurel Creek Mines

The Laurel Creek mining complex consists of three underground mines, as well as surface reserves. The #1 and #8 mines operate in the Coalburg Seam and the #6 mine operates in the Cedar Grove seam. The preparation plant is located in Logan and Mingo Counties. In 2008, the mines shipped 1.0 million tons and as of December 31, 2008 had approximately 23.7 million tons of assigned reserves (both underground and surface) and approximately 9.6 million tons of unassigned reserves. The coal is shipped by truck primarily to our Rivereagle dock, other third-party docks or our rail siding on CSX Transportation.

On January 30, 2009, an affiliate of the Company idled the Laurel Creek mining complex. The decision to idle the Laurel Creek mining complex was due to certain business conditions. The Company expects to record approximately $2.1 million in employee severance and medical continuance costs in accordance with SFAS No. 146. The Laurel Creek mining complex is included in the Company's Central Appalachia segment. See Note 21 to the Consolidated Financial Statements contained elsewhere in this Annual Report on Form 10-K.

Rockspring Mine

Rockspring Development, Inc. operates a large multiple section mining complex in Wayne County called Camp Creek that produces coal from the Coalburg Seam. The complex shipped 2.9 million tons of coal in 2008. Assigned and unassigned coal reserves totaled approximately 38.0 million tons and 22.7 million tons, respectively. Rockspring has a mine site rail loadout served by Norfolk Southern Railway. The coal is transported primarily to southeastern utilities. The mine can also ship a portion of its production by truck.

Pioneer Mines

Pioneer Fuel Corporation operates two surface mines: Paynter Branch, which is located in Wyoming County, and Pax surface mine, which is located in Raleigh County. These mines utilize front-end loaders with trucks to mine multiple seams. The Pioneer mines shipped 1.5 million tons of steam and metallurgical coal in 2008. As of December 31, 2008, the mines had assigned reserves of approximately 18.8 million tons with an additional 13.4 million tons of unassigned reserves. Based on 2008 production rates, we expect that the Pax mine has sufficient reserves to last approximately 11 years. The Paynter Branch mine will complete mining activities on the permitted area in 2009. Coal from Paynter Branch is shipped by truck to our on-site rail loading facility on the Norfolk Southern Railway and then on to domestic utilities and exported to metallurgical coal customers. Coal from Pax is shipped to customers primarily via rail, with coal being trucked from the mine to our on-site train loading facility served by CSX Transportation/R.J. Corman Railroad. Pax coal may also be trucked to the Kanawha River for shipment by barge.

Illinois Operations

Wabash Mine

The Wabash mine, a room-and-pillar operation, located in Wabash County, Illinois was placed on long-term idle status on April 4, 2007 due to a combination of factors, including aged underground infrastructure, softening market conditions, escalating labor and operating costs and higher value uses for capital. Remaining reserves at the property total 26.1 million tons in the Illinois No. 5 seam. The mine and related facilities are fully permitted. Idle facilities include a preparation plant and rail loading facility on the Norfolk Southern Railway. If market conditions warrant, the mine could be re-opened with less capital investment than would be required to develop a new underground mine.

Long-Term Coal Supply Agreements

As of January 26, 2009, we had a total sales backlog of over 259 million tons of coal, and our coal supply agreements have remaining terms ranging from less than one year to 13 years. For 2008, we sold approximately 86% of our sales volume under long-term coal supply agreements with duration of longer than twelve months. Our primary customer base is in the United States. We expect to continue selling a significant portion of our coal under long-term supply agreements. Our strategy is to selectively renew, or enter into new, long-term supply contracts when we can do so at prices we believe are favorable. As of January 26, 2009, we had sales and price commitments for approximately 97% of our planned 2009 shipments, approximately 59% of our planned 2010 shipments and approximately 29% of our planned 2011 shipments. To the extent we do not renew or replace expiring long-term coal supply agreements, our future sales have increased exposure to market fluctuations.

The terms and conditions of our coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, contract provisions vary by customer, including price adjustment features, coal quality requirements, future regulatory changes (including changes in environmental laws) affecting us or our customers, pass-through of new government impositions, and force majeure provisions.

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

Some of our contracts set out mechanisms for temporary reductions or delays in coal volumes in the event of a force majeure, including events such as labor strikes or lockouts, equipment failures, regulatory issues, adverse mining conditions, unanticipated plant outages, or serious transportation problems that affect us or our customers. Disputes may arise regarding whether force majeure has been properly declared by us or our customers, and resulting shortfalls may result in significant damages claims by or against us based on differences between contract prices and market prices.

Sales and Marketing

Our sales, marketing, and trading affiliate, Foundation Energy Sales, Inc., employs staff to handle trading, transportation, market research, contract administration, and related risk and credit management activities. Our sales team has an average of over 20 years of experience in the areas of coal sales and procurement, trading, and transportation. Through our sales, trading and marketing entity, we sell coal produced by our diverse portfolio of affiliate operations, broker coal sales of other coal producers, trade coal and emission allowances and provide transportation related services.

Transportation

Coal consumed domestically is usually sold at the mine, and transportation costs are normally borne by the purchaser. Export coal is usually sold at the loading port, with purchasers responsible for further transportation. Producers usually pay shipping costs from the mine to the port.

We depend upon rail, barge, trucking and other systems to deliver coal to markets. In 2008, our produced coal was transported from the mines and to the customer primarily by rail, with the main rail carriers being CSX Transportation, Norfolk Southern Railway Company, BNSF Railway and Union Pacific Railroad Company. The majority of our sales volume is shipped by rail, but a portion of our production is shipped by barge and truck. All coal from our Belle Ayr mine in Wyoming is shipped by two competing railroads, the BNSF Railway and the Union Pacific Railroad Company, while rail shipments from our Eagle Butte operation move via the BNSF Railway. The Pioneer, Kingston, Laurel Creek and Rockspring mines in West Virginia are serviced by rail, primarily by a combination of the Norfolk Southern Railway Company and CSX Transportation, as well as by truck and barge. In Pennsylvania, the Emerald mine is serviced by the Norfolk Southern Railway Company and CSX Transportation and the Cumberland mine is primarily serviced by barge. We move the coal from the Cumberland mine approximately 17 miles to the river for loading into barges on a captive railroad line we own and operate.

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

Suppliers

We spend more than $600 million per year to procure goods and services in support of our business activities, excluding capital expenditures. Principal goods and services include maintenance and repair parts and services, electricity, fuel, roof control and support items, explosives, tires, conveyance structure, ventilation supplies and lubricants. We use suppliers for a significant portion of our equipment rebuilds and repairs both on- and off-site, as well as construction and reclamation activities and to support computer systems.

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

Employees

As of December 31, 2008, we and our subsidiaries had approximately 3,300 employees. As of December 31, 2008, pursuant to two distinct collective bargaining agreements that expire in 2011, the UMWA represented approximately 34% of our affiliates' employees, who produced approximately 19% of our coal sales volume during the fiscal year ended December 31, 2008. Relations with organized labor are important to our success, and we believe our relations with our employees are satisfactory.

ENVIRONMENTAL AND OTHER REGULATORY MATTERS

Federal, state and local authorities regulate the United States coal mining and oil and gas industries with respect to matters such as: employee health and safety; permitting and licensing requirements; emissions to air and discharges to water; plant and wildlife protection; the reclamation and restoration of properties after mining or other activity has been completed; the storage, treatment and disposal of wastes; remediation of contaminated soil; protection of surface and groundwater; surface subsidence from underground mining; the effects on surface and groundwater quality and availability; noise; dust and competing uses of adjacent, overlying or underlying lands such as for oil and gas activity, pipelines, roads and public facilities. These ordinances, regulations and legislation (and judicial or agency interpretations thereof) have had, and will continue to have, a significant effect on our production costs and our competitive position. New laws and regulations, as well as future interpretations or different enforcement of existing laws and regulations, may require substantial increases in equipment and operating costs to us and delays, interruptions, or a termination of operations, the extent of which we cannot predict. We intend to respond to these regulatory requirements and interpretations thereof at the appropriate time by implementing necessary modifications to facilities or operating procedures. When appropriate, we may also challenge actions in regulatory or court proceedings. Future legislation, regulations, interpretations or enforcement may also cause coal to become a less attractive fuel source due to factors such as investments necessary to use coal or taxes imposed upon its use. As a result, future legislation, regulations, interpretations or enforcement may adversely affect our mining or other operations, cost structure or the ability of our customers to use coal.

We endeavor to conduct our mining and other operations in compliance with all applicable federal, state, and local laws and regulations. However, violations occur from time to time. None of the violations identified or the monetary penalties assessed upon us in recent years has been material. It is possible that future liability under or compliance with environmental and safety requirements could have a material effect on our operations or competitive position. Under some circumstances, substantial fines and penalties, including revocation or suspension of mining or other permits, may be imposed under the laws described below. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Mine Safety and Health

The Coal Mine Health and Safety Act of 1969 and the Federal Mine Safety and Health Act of 1977 impose stringent safety and health standards on all aspects of mining operations. Also, most of the states in which we operate have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is perhaps one of the most comprehensive and pervasive system for protection of employee health and safety affecting any segment of U.S. industry. Regulation has a significant effect on our operating costs.

Since early 2006 and continuing to the present, as a result of the 2006 Sago mine incident in West Virginia, the 2006 Darby mine incident in Kentucky, and other incidents in the coal mining industry, legislative and regulatory bodies at the state and federal levels including MSHA have promulgated or proposed various new statutes, regulations and policies relating to mine safety and mine emergency issues. In the case of MSHA, the MINER Act passed in 2006 mandated mine rescue regulations, new and improved technologies and safety practices in the area of tracking and communication, and emergency response plans and equipment. Although some new laws, regulations and policies are in place, these legislative and regulatory efforts are still ongoing. At this time, it is not possible to predict the full effect that the new or proposed statutes, regulations and policies will have on our operating costs, but it will increase our costs and those of our competitors. Some, but not all, of these additional costs may be passed on to customers.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and to a trust fund for the payment of benefits and medical expenses to eligible claimants. The trust fund is funded by an excise tax on production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

In December 2000, the Department of Labor amended regulations implementing the federal black lung laws to, among other things, establish a presumption in favor of a claimant's treating physician and limit a coal operator's ability to introduce medical evidence regarding the claimant's medical condition. The number of claimants who are awarded benefits has since increased, and will continue to increase, as will the amounts of those awards.

As of December 31, 2008, all of our various payment obligations for federal black lung benefits to claimants entitled to such benefits are made from a tax exempt trust established for that purpose. Based on actuarial reports and required funding levels, from time to time we may have to supplement the trust corpus to cover the anticipated liabilities going forward.

Coal Industry Retiree Health Benefit Act of 1992

The Coal Industry Retiree Health Benefit Act of 1992 (the "Coal Act") provides for the funding of health benefits for certain UMWA retirees and their spouses or dependants. The Coal Act established the Combined Benefit Fund into which employers who are "signatory operators" are obligated to pay annual premiums for beneficiaries. The Combined Benefit Fund covers a fixed group of individuals who retired before July 1, 1976, and the average age of the retirees in this fund is over 80 years of age. Premiums paid in 2008 for our obligations to the Combined Benefit Fund were approximately $0.9 million. The Coal Act also created a second benefit fund, the 1992 UMWA Benefit Plan ("the 1992 Plan"), for miners who retired between July 1, 1976 and September 30, 1994, and whose former employers are no longer in business to provide them retiree medical benefits. Companies with 1992 Plan liabilities also pay premiums into this plan. Premiums paid in 2008 for our obligation to the 1992 Plan were approximately $1.0 million. These per beneficiary premiums for both the Combined Benefit Fund and the 1992 Plan are adjusted annually based on various criteria such as the number of beneficiaries and the anticipated health benefit costs.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 became law and will have the impact of reducing or eliminating the premium obligation of companies due to the expanded transfers from the Abandoned Mine Land Fund ("AML"). The additional transfer of funds from AML will incrementally eliminate by 2010, to the extent the new transfers are adequate, the unassigned beneficiary premium under the Combined Benefit Fund effective October 1, 2007. The additional transfers will also reduce incrementally the pre-funding and assigned beneficiary premium to cover the cost of beneficiaries for which no individual company is responsible ("orphans") under the 1992 Plan beginning January 1, 2008. For the first time, the 1993 Benefit Plan ("the 1993 Plan") (all of the beneficiaries of which are orphans) will begin receiving a subsidy from a new federal transfer that will ultimately cover the entire cost of the eligible population as of December 31, 2006. Under the Combined Benefit Fund, the 1992 Plan and the 1993 Plan, if the federal transfers are inadequate to cover the cost of the "orphan" component, the current or former signatories of the UMWA wage agreement will remain liable for any shortfall.

Environmental Laws

We and our customers are subject to various federal, state and local environmental laws. Some of the more material of these laws and issues, discussed below, place stringent requirements on our coal mining and other operations, and on the ability of our customers to use coal. Federal, state and local regulations require regular monitoring of our mines and other facilities to ensure compliance with these many laws and regulations.

Mining Permits and Necessary Approvals

Numerous governmental permits, licenses or approvals are required for mining, oil and gas operations, and related operations. When we apply for these permits and approvals, we may be required to present data to federal, state or local authorities pertaining to the effect or impact our operations may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining or other operations. These requirements may also be added to, modified or re-interpreted from time to time. Regulations also provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a stockholder with a 10% or greater interest in the entity is affiliated with or is in a position to control another entity that has outstanding mining permit violations. Thus, past or ongoing violations of federal and state mining laws could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from state regulatory authorities, we must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior or better condition, productive use or other permitted condition. Typically, we submit our necessary permit applications several months, or even years, before we plan to begin mining a new area. In the past, we have generally obtained our mining permits in time so as to be able to run our operations as planned. However, we may experience difficulty or delays in obtaining mining permits or other necessary approvals in the future, or even face denials of permits altogether. In particular, issuance of Army Corps of Engineers (the "COE") permits in Central Appalachia allowing placement of material in valleys have been slowed in recent years due to ongoing litigation over the requirements for obtaining such permits. These delays could spread to other geographic regions as litigation or legislation progresses.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act of 1977 (the "SMCRA"), which is administered by the Office of Surface Mining Reclamation and Enforcement within the Department of the Interior (the "OSM"), establishes mining, environmental protection and reclamation standards for all aspects of surface mining, as well as many aspects of deep mining that impact the surface. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the regulatory authority with primacy and issues the permits, but OSM maintains oversight. SMCRA stipulates compliance with many other major environmental statutes, including the federal Clean Air Act, Clean Water Act, Resource Conservation and Recovery Act ("RCRA") and Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or "Superfund").

SMCRA permit provisions include requirements for, among other actions, coal prospecting; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; surface drainage control; mine drainage and mine discharge control and treatment; and re-vegetation. The permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural and historical resources, soils, vegetation, wildlife, assessment of surface and ground water hydrology, climatology, and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mining and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mining and reclamation plan incorporates the provisions of SMCRA, the state programs, and the complementary environmental programs that affect coal mining. Also included in the permit application are documents defining ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land.

Some SMCRA mine permits take over a year to prepare, depending on the size and complexity of the mine. Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness review and technical review. Public notice of the proposed permit is given that also provides for a comment period before a permit can be issued. Some SMCRA mine permits may take several years or even longer to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public and other agencies have rights to comment on and otherwise engage in the permitting process, including through intervention in the courts.

Under the Stream Buffer Zone Rule issued under SMCRA in 1983, mining disturbances were prohibited within 100 feet of streams if negative effects on water quality were expected. Neither OSM nor any of the states interpreted the rule as prohibiting excess spoil disposal in streambeds under Section 404 of the Clean Water Act. Due to differing interpretations of the rule being applied, OSM worked for several years to revise and clarify the Stream Buffer Zone Rule. OSM proposed changes to this rule which would make exemptions available if mine operators take steps to reduce the amount of waste and its effect on nearby waters. Many comments to this proposed rule, both for and against, were filed during this process. In December 2008 OSM finalized the proposed rule to clarify the Stream Buffer Zone Rule. The new rule allows disposal of excess spoil within 100 feet of streams, but requires OSM to make findings of impact minimization that overlap findings required by the COE in administration of the Clean Water Act Section 404 program. Since the rule was finalized, several environmental groups have filed legal challenges against both OSM and the EPA challenging not just the rule, but the EPA's written concurrence which is required by SMCRA. Legislation in Congress has been introduced in the past and may be introduced in the future in an attempt to preclude placing any mining material in streams. Such legislation would have a material adverse impact on future ability to conduct certain types of mining activity. Surface mining would likely be more adversely impacted.

Mountaintop removal mining is a legal but controversial method of surface mining. This mining method accounted for less than three percent of our total 2008 coal production. Certain anti-mining special interest groups have recently waged a public relations assault upon this mining method and have encouraged the introduction of legislation at the state and federal level to restrict or ban it and to preclude purchasing coal mined by this method. Should changes in laws, regulations or availability of permits severely restrict or ban this mining method in the future, our production and associated profitability could be adversely impacted.

Before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of reclamation obligations. The AML, which is part of SMCRA, requires a fee on all coal produced. The proceeds are used to reclaim mine lands closed prior to 1977 when SMCRA came into effect. The current fee is \$0.315 per ton on surface-mined coal and \$0.135 on deep-mined coal from 2008 to 2012, with reductions to \$0.28 per ton on surface-mined coal and \$0.12 per ton on deep-mined coal from 2013 to 2021.

Surety Bonds

Federal and state laws require us to obtain surety bonds to secure payment of certain long-term obligations including mine closure or reclamation costs, federal and state workers' compensation costs, obligations under federal coal leases and other miscellaneous obligations. Many of these bonds are renewable on a yearly basis. In recent years, surety bond premium costs have increased and the market terms of surety bonds have generally become more unfavorable. In addition, the number of companies willing to issue surety bonds has decreased. We cannot predict the ability to obtain or the cost of bonds in the future.

Clean Air Act

The Clean Air Act, the Clean Air Act Amendments and the corresponding state laws that regulate the emissions of materials into the air affect coal mining operations both directly and indirectly. Direct impacts on coal mining and processing operations may occur through Clean Air Act permitting requirements and/or emission control requirements relating to particulate matter, such as fugitive dust, including future regulation of fine particulate matter measuring 10 micrometers in diameter or smaller. The Clean Air Act indirectly affects coal mining operations by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, particulates, mercury and other compounds emitted by coal-fueled electricity generating plants and industrial facilities which burn coal. Power plants will likely have to continue to install pollution control technology and upgrades. Power plants may be able to recover the costs for these upgrades in the prices they charge for power, but this is not a certainty and state public utility commissions often control such rate matters. The Clean Air Act provisions and associated regulations are complex, lengthy and often being assessed for revisions or additions. In addition, one or more of the pertinent state or federal regulations issued as final are at this time, and may still continue to be, subject to current and future legal challenges in courts and the actual timing of implementation may remain uncertain. Some of the more material Clean Air Act requirements that may directly or indirectly affect our operations include the following:

- *Acid Rain.* Title IV of the Clean Air Act required a two-phase reduction of sulfur dioxide emissions by electric utilities. Phase II became effective in 2000 and applies to all coal-fired power plants generating greater than 25 megawatts. The affected electricity generators have sought to meet these requirements mainly by, among other compliance methods, switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing sulfur dioxide emission allowances. The adoption of the Clean Air Interstate Rule ("CAIR") in 2005 created tighter limits for sulfur dioxide and nitrogen oxides for the states covered under CAIR than currently exist under Title IV. (See "Clean Air Interstate Rule" for more information.) The cap-and-trade program under the CAIR utilizes the same allowance allocation policy developed under Title IV of the Clean Air Act. States not governed by the CAIR will continue to be subject to the regulations of Title IV. We cannot accurately predict the effect of these provisions of the Clean Air Act on us in future years. Initially, we believe that implementation of Phase II resulted in an upward pressure on the price of lower sulfur eastern coals, and more demand for western coals, as coal-fired power plants continue to comply with the more stringent restrictions of Title IV. As utilities continue to invest the capital to add scrubbers and other devices to comply with Title IV, CAIR, the Clean Air Mercury, or "CAMR", or possible regulations requiring maximum achievable control technology to limit mercury emissions (discussed below) and other provisions of the law, demand for lower sulfur coals may drop.
- *Fine Particulate Matter and Ozone.* The Clean Air Act requires the Environmental Protection Agency ("EPA") to set standards, referred to as National Ambient Air Quality Standards ("NAAQS"), for certain pollutants. Areas that are not in compliance (referred to as "non-attainment areas") with these standards must take steps to reduce emissions levels. In 1997, the EPA revised the NAAQS for particulate matter and ozone. Although previously subject to legal challenge, these revisions were subsequently upheld but implementation was delayed for several years. For ozone, these changes include replacement of the existing one-hour average standard with a more stringent eight-hour average standard in Phase 1 of the Ozone Rule. In April 2004, the EPA announced that counties in 31 states and the District of Columbia failed to meet the new eight-hour standard for ozone. On November 8, 2005, the EPA finalized Phase 2 of the Ozone Rule, which establishes the final compliance requirements and timelines upon which state, local, and tribal government will base their state implementation plans for areas designated as non-attainment. For particulates, the changes include retaining the existing standard for particulate matter with an aerodynamic diameter less than or equal to 10 microns ("PM10"), and adding a new standard for fine particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ("PM2.5"). State fine particulate non-attainment designations were finalized in December 2005, and counties in 21 states and the District of Columbia were classified as non-attainment areas. At the same time, the EPA also proposed changes to the current national air quality monitoring requirements for all criteria pollutants including particulates and revisions to the national air quality standards for fine particulate pollution, proposing more stringent requirements for this pollutant. These newly proposed standards were incorporated into the EPA's final rule on particulate matter issued in October 2006. These standards also include making new state non-attainment designations in 2010 based on 2007-2009 air quality data; requiring these states to meet the EPA's new PM standards by 2015. Meeting the new PM2.5 standard may require reductions of nitrogen oxide and sulfur dioxide emissions. On March 29, 2007, the EPA issued a final rule defining requirements for state plans to clean the air in 39 areas where particle pollution levels do not meet national air quality standards. Future regulation and enforcement of these new ozone and PM2.5 standards will affect many power plants, especially coal-fired plants and all plants in "non-attainment" areas. These events may change the demand for coal.

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

- *NOx SIP Call.* The NOx SIP Call program was established by the EPA in October of 1998 to reduce the transport of ozone on prevailing winds from the Midwest and South to states in the Northeast, which said they could not meet federal air quality standards because of migrating pollution. Under Phase I of the program, the EPA required 90,000 tons of nitrogen oxides reductions from power plants in 22 states east of the Mississippi River and the District of Columbia beginning in May 2004. Phase II of the program, which became effective in June 2004, required a further reduction of about 100,000 tons of nitrogen oxides per year by May 2007. The installation, operation and maintenance of these additional control measures, such as selective catalytic reduction devices, required under the final rules will make it more costly to operate coal-fired electricity generating plants.

- *Clean Air Interstate Rule.* In 2004, the EPA proposed new rules for further reducing emissions of sulfur dioxide and nitrogen oxides. The final CAIR was issued by the EPA in 2005. The rule calls for power plants in Texas and 27 states bordering or east of the Mississippi River, and the District of Columbia, to reduce emission levels of sulfur dioxide and nitrous oxide. At full implementation, CAIR was estimated by the EPA to cut regional sulfur dioxide emissions by more than 70% from the 2003 levels, and to cut nitrogen oxide emissions by more then 60% from 2003 levels. States had to achieve the required emission reductions using one of two compliance options. The first alternative was for the state to require power plants to participate in an EPA administered "cap-and-trade" system that caps emissions in two stages. This cap and trade approach is similar to the system now in effect under other regulations controlling air pollution. Alternatively, a state could elect to meet a specific state emissions budget through measures of the state's choosing. These state measures had to be at least as stringent as those imposed by CAIR. After the passage of CAIR, different entities and organizations challenged the rule on various bases. The U.S. Court of Appeals for the D.C. Circuit (*State of North Carolina, et al. v. EPA*, No. 05-1244) on July 11, 2008 issued its decision in litigation challenging CAIR. The decision vacated CAIR and the CAIR federal implementation plan in their entirety. The decision remanded CAIR to EPA to promulgate a rule that complies with the court's opinion. The court ruled against the EPA on several of the core aspects of the rule, including: CAIR's use of unrestricted interstate trading; the 2015 compliance deadline for Phase 2 of CAIR; the use of Title IV allowances at a heightened surrender ratio for compliance with the SO_2 part of CAIR; and EPA's determination of the SO_2 and NOx emission budgets. The court also struck down emission allowance trading in CAIR, holding that unrestricted trading might result in no emission reductions in an upwind state, thereby preventing the EPA from fulfilling its responsibility under the Clean Air Act to prohibit sources in one state from contributing to non-attainment in another state. Ultimately, this ruling may significantly impact the EPA's potential future ability to address interstate pollution transport with a cap-and-trade system. The court also rejected an EPA "fairness" argument and ruled that it was inappropriate for the EPA to divide a region wide NOx budget among the states, and essentially remove each state's responsibility to eliminate its own significant contribution to downwind pollution. After this ruling, later in 2008 the EPA petitioned the court for a rehearing. After briefing by all parties, in December 2008 the court ruled that a complete vacatur of the rule would sacrifice clear benefits to public health and the environment while the EPA works to fix the deficiencies found by the court. Thus CAIR will be in effect while the EPA modifies the rule. How the EPA will proceed to modify CAIR is uncertain at this time. Ultimately, the stringency of the caps may require many coal-fired sources to install additional pollution control equipment to comply. This increased sulfur emission removal capability caused by the proposed rule could result in decreased demand for low sulfur coal, potentially driving down prices for low sulfur coal. Individual states covered by CAIR may proceed to develop their own regulations in this area which may differ, and therefore may be more difficult to implement and operate within. The decision may affect the price of allowances purchased and sold related to emission of SO_2 and NOx, and this in turn may increase or decrease the demand for certain coals. If the prices for allowances change, this may affect the penalties imposed or premiums paid under the contracts through which we sell our coal. These factors and any new legislation, if enacted, could have a material adverse effect on our financial condition and results of operations or cash flow.

- *Clean Air Mercury Rule.* In December 2000, the EPA decided to list coal-fired power plants as a category of sources subject to regulation under section 112 of the Clean Air Act. Section 112 governs hazardous air pollutants from stationary sources. In January 2004, the EPA proposed a mercury reduction rule for controlling mercury emissions from power plants and requested comments on two approaches for reducing mercury currently emitted each year by coal-fired power plants in the United States. After reconsidering its prior decision to regulate power plant emissions of mercury under section 112, EPA reversed its prior "listing" decision and issued its final CAMR, in March 2005. In doing so, the EPA rejected the approach which would require coal-fired power plants to install pollution controls known as "maximum achievable control technologies", or "MACT", under section 112 of the Clean Air Act. The approach the EPA adopted, which was challenged in federal court by several states and others, set a mandatory, declining cap on the total mercury emissions allowed from coal-fired power plants nationwide pursuant to section 111 of the Clean Air Act. This "cap-and-trade" approach is similar to the approach under the CAIR rule discussed above. If implemented, the CAMR approach, which allows mercury emissions trading, when combined with the CAIR regulations, was forecast to reduce mercury emissions by nearly 70% from current levels once facilities reach a final mercury cap which takes effect in 2018. Current mercury emissions from United States power plants are about 48 tons per year. The first phase cap is 38 tons and was scheduled to begin in 2010. EPA estimates that much of this reduction will come as a "co-benefit" of the pollution control devices installed under the CAIR regulations. The final cap was set at 15 tons per year beginning in 2018. Under the EPA approach, each state would be allocated a budget of mercury emissions and required to submit a plan on meeting its budget for mercury reductions. Each state is not required to adopt the cap-and-trade approach, but instead can elect to meet a specific state emissions budget through measures of the state's choosing. The stringency of the caps may require many coal-fired sources to install additional pollution control equipment to comply. This increased mercury emission removal capability caused by the proposed rule could result in decreased demand for certain coals either due to higher mercury levels or more difficulty in removing the inherent mercury. In November 2006, states were required to file their state implementation plans ("SIP") with the EPA for mercury compliance but only 21 states submitted plans. This prompted the EPA to designate a federal implementation plan ("FIP") to be applied to states that did not file a SIP. The FIP basically requires all states without an EPA approved SIP to participate in the national cap-and-trade program. On February 8, 2008, the United States Court of Appeals for the District of Columbia Circuit struck down the EPA's regulations for reducing mercury emissions from coal-fired power plants. The court held that the EPA violated the Clean Air Act by reversing its prior decision to list coal-fired power plants as a source of emissions subject to regulation under Clean Air Act section 112. According to the court, once the EPA initially determined under section 112(n)(1) of the Clean Air Act that it was "appropriate and necessary" to regulate those plants under the Clean Air Act's hazardous air pollutant program, the agency could not reverse its own decision under that same provision. Rather, the court held that section 112(c)(9) of the Act affords the exclusive mechanism to remove any source from the list of sources regulated under the hazardous air pollutant program. That provision requires a more exacting finding to remove sources, including a determination that no adverse environmental effect will result from emissions from any source. Because the effect of the court's ruling is to maintain power plants on the list of hazardous air pollutant sources subject to regulation under section 112, the court concluded that regulation of mercury emissions from existing coal-fired plants under section 111 is prohibited, thereby invalidating the CAMR's regulatory approach. Both the EPA and industry appealed the decision to the United States Supreme Court after the lower court denied a petition for rehearing. In February 2009, the EPA announced it would withdraw this appeal and proceed to draft regulations for use of MACT under section 112 of the Clean Air Act, and the United States Supreme Court declined to rehear the case. The EPA rulemaking process will likely take several years. After a rule is issued, affected utilities would have three years to comply with the standard. Separate state standards may also be passed and applied in the interim, and the Obama Administration has announced a desire to begin negotiations on an international treaty to cut mercury pollution. A MACT standard could increase the cost of consuming coal and impact the demand for coals with various amounts or compounds of mercury contained therein.

- *Carbon Dioxide and other greenhouse gases.* In 2003, certain states sued the EPA seeking a court order requiring the EPA to designate carbon dioxide as a criteria pollutant under the Clean Air Act and to issue a new NAAQS for carbon dioxide. Previously, the EPA had established that carbon dioxide is not a criteria pollutant and therefore cannot be regulated under the Clean Air Act. In 2005, a federal court upheld the EPA's position that it was not required to regulate carbon dioxide as a pollutant. In April 2007, in *Massachusetts v. Environmental Protection Agency*, the United States Supreme Court case ruled in a 5-4 decision the Clean Air Act does give the EPA the authority to regulate tailpipe emissions of greenhouse gases. In addition, the majority held that "greenhouse gases fit well within the Clean Air Act's capacious definition of air pollutant." In July 2008 the EPA issued an Advance Notice of Proposed Rulemaking for the regulation of greenhouse gas emissions under the Clean Air Act. The notice details the potential ramifications of regulating these gases for both mobile and stationary sources and the potential effects on the U.S. economy and how we conduct our operations. The ultimate actions of the EPA as a result of this Supreme Court decision may affect the demand for coal. In addition, there are several new state programs to limit CO_2 emissions and others have been proposed. There are also pending before Congress several proposals to limit CO_2 emissions and other proposals may be forthcoming. Various House and Senate committees are conducting hearings into the issues surrounding climate change and the effects of CO_2 emissions and other greenhouse gases. Congress, or one or more states, at some point, is likely to regulate and may limit the release of carbon dioxide emissions as part of any green house gas initiatives that are proposed in the future. See "Climate Change" for further information. These limitations could affect the future market for coal and how we conduct our operations.

- *Regional Haze.* The EPA has initiated a regional haze program designed to protect and to improve visibility at and around national parks, national wilderness areas and international parks. The original regional haze rule required designated facilities to meet the EPA's BART standard, which requires installation of the Best Available Retrofit Technology to reduce emissions that contribute to visibility problems. In December 2006, this rule was modified to allow states the flexibility to evaluate the use of cap-and-trade programs when these programs would result in greater progress toward the EPA's visibility goals. This program restricts the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas. Moreover, this program may require certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. These limitations could affect the future market for coal.

Climate Change

One major by-product of burning coal and all other fossil fuels 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 (the "Protocol") to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for greenhouse gases. With Russia's ratification, the Protocol received sufficient support to become binding on all those countries that have ratified it. Although the targets vary from country to country, if the United States were to ratify the Protocol, the United States would be required to reduce greenhouse gas emissions to 93% of 1990 levels from 2008 to 2012. In 2002, President Bush reaffirmed U.S. support for the United Nations Framework Convention on Climate Change, but the U.S. Senate did not ratify the Protocol because, among other reasons, it did not require emissions reduction from all countries. The Protocol expires in 2012. Many of the countries which did ratify the Protocol are not on target to meet the mandated reductions in carbon dioxide. In addition, many developing nations which also emit greenhouse gases are not covered by the Protocol. As such, a new or modified international protocol to regulate carbon dioxide emissions will likely be proposed in the future.

As part of the United Nations Framework Convention on Climate Change, representatives from 187 nations met in Bali, Indonesia in December 2007 to discuss a program to limit greenhouse gas emissions after 2012. The United States participated in the conference. The convention adopted what is called the "Bali Action Plan." The Bali Action Plan contains no binding commitments, but concludes that "deep cuts in global emissions will be required" and provides a timetable for two years of talks to shape the first formal addendum to the 1992 United Nations Framework Convention on Climate Change treaty since the Kyoto Protocol. The ultimate outcome of the Bali Action Plan, and any treaty or other arrangement ultimately adopted by the United States or other countries, may have a material adverse impact the global supply and demand for coal. This is particularly true if cost effective technology for the capture and sequestration of carbon dioxide is not sufficiently and timely developed.

Future regulation of greenhouse gases in the United States could occur pursuant to future United States treaty obligations, statutory or regulatory changes under the Clean Air Act, or otherwise at the state and federal level. The Bush Administration proposed a package of voluntary emission reductions for greenhouse gases reduction targets which provide for certain incentives if targets are met. The Obama Administration is more likely to support mandatory emission reductions for greenhouse gases. There are also various federal, state and local legislative initiatives aimed at tracking or regulating, both on a mandatory or voluntary basis, the release of carbon dioxide from generating power and other commercial activity. In 2002, the Conference of New England Governors and Eastern Canadian Premiers adopted a Climate Change Action Plan, calling for reduction in regional greenhouse emissions to 1990 levels by 2010, and a further reduction of at least 10% below 1990 levels by 2020. Currently several state groups are working on regional plans to address climate and energy issues. The new Congress has been active in promoting greenhouse gas legislation with several separate bills already being presented and others possible. There are a number of uncertainties regarding these and additional initiatives which may be proposed. In addition to the timing for implementing any new legislation, open issues include matters such as the applicable baseline of emissions to be permitted, initial allocations of any emission allowances, required emissions reductions, availability of offsets to emissions such as planting trees or capturing methane emitted during mining, the extent to which additional states will adopt the programs, and whether they will be linked with programs in other states or countries. Increased efforts to control greenhouse gas emissions could result in reduced demand for coal and increased costs to consume coal and to conduct our operations.

Clean Water Act

The Clean Water Act of 1972 (the "CWA") and corresponding state laws affect coal mining operations by imposing restrictions on the discharge of certain pollutants into water and on dredging and filling wetlands. The CWA establishes in-stream water quality standards and treatment standards for wastewater discharge through the National Pollutant Discharge Elimination System ("NPDES"). Regular monitoring, as well as compliance with reporting requirements and performance standards, are preconditions for the issuance and renewal of NPDES permits that govern the discharge of pollutants into water. The CWA provisions and associated regulations are complex, lengthy and often being assessed for revisions or additions. In addition, one or more of the pertinent state or federal regulations issued as final are at this time, and may still continue to be, subject to current and future amendments or legal challenges in courts and the actual timing of implementation may remain uncertain. Some of the more material CWA issues that may directly or indirectly affect our operations are discussed below.

Permits under Section 404 of the CWA are required for coal companies to conduct dredging or filling activities in jurisdictional waters for the purpose of creating slurry ponds, water impoundments, refuse disposal areas, valley fills or other mining activities. Jurisdictional waters typically include ephemeral, intermittent, and perennial streams and may in certain instances include man-made conveyances that have a hydrologic connection to a stream or wetland. The COE only has jurisdiction over the "navigable waters" of the United States, and outside these waters there is arguably no need to procure a 404 permit. The United States Supreme Court ruled in

Rapanos v. United States in 2006 that upper reaches of streams which are intermittent or do not flow might not be jurisdictional waters requiring 404 permits. The case did not involve disposal of mining refuse, but has implications for the mining industry. Subsequently, in June 2007 the COE and EPA issued a joint guidance document to attempt to develop a policy that will apply the jurisdictional standards imposed by the Supreme Court. The guidance requires a case-by-case analysis of whether the area to be filled has a sufficient nexus to downstream navigable waters so as to require 404 permits. How the COE field offices will apply this new guidance, and to what extent decisions made pursuant to it will be challenged, are still open questions.

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

In March 2007, the U.S. District Court for the Southern District of West Virginia issued a decision concerning 404 permitting for fills. The court held that widely used pre-mining assessments of areas to be impacted required by the COE and conducted by the permit applicants are inadequate and do not accurately assess the nature of the headwater areas being filled. As such, the court found the COE erred in its finding of no significant impact from this activity. Based on this conclusion, the court went on to find that proposed mitigation to offset the adverse impacts of the area to be filled also are not supported by adequate data. Due to this decision, the COE is assessing the protocol for evaluating the pre-mining stream conditions, as well as procedures used in the measurement of the success of mitigation. That effort to revise the protocol and associated findings is ongoing and may be challenged as it is applied to newly issued permits. Until this process is completed, preparing and submitting new permit applications is somewhat hindered. The March 2007 decision was appealed to the Fourth Circuit Court of Appeals. In June 2007, the same federal district court also effectively prohibited mine operators from impounding streams below their valley fills for the purpose of constructing sediment ponds. Mine operators are required to route drainage from valley fills to sediment control structures and to meet NPDES permit limits for discharges from those structures. In the steep sloped areas of Central Appalachia, often the only practicable location for those structures is in the stream channel itself downstream of the valley fills. The COE and EPA had both considered such ponds to be "treatment systems" excluded from the definition of "waters of the United States" to which the Clean Water Act applies. The court's June 2007 opinion, though, held that these ponds remain "waters of the United States" and that mine operators must meet effluent limits for discharges into the ponds as well as from the ponds. Meeting these limits at the point where water first leaves a valley fill or enters the stream or pond would be difficult. This decision was also appealed to the Fourth Circuit Court of Appeals. In February 2009, based on a 2-1 decision, the Fourth Circuit Court of Appeals overturned these lower court decisions. The plaintiffs may seek a rehearing or appeal this ruling to the United States Supreme Court. Legislation may be introduced at the state or federal level in order to override this decision by the Court of Appeals. An outcome that prevents the placement of mining spoil or refuse into valleys could have a material adverse impact on the ability to maintain current operations and to permit new operations.

In December 2007, a similar case was filed in the U.S. District Court for the Western District of Kentucky challenging a single permit issued by the COE in Leslie County. That permit has been suspended by the COE so that it can reconsider the permit decision to address comments of the environmental group that filed the lawsuit. Although we do not have operations in Kentucky, the decision in this matter may affect permits in states where we do have operations.

The COE is empowered to issue nationwide permits for specific categories of filling activity that are determined to have minimal environmental adverse effects in order to save the cost and time of issuing individual permits under Section 404. Nationwide Permit 21 authorizes the disposal of dredge-and-fill material from mining activities into the waters of the United States. On October 23, 2003, several citizens groups sued the COE in the United States District Court for the Southern District of West Virginia seeking to invalidate nationwide permits utilized by the COE and the coal industry for permitting most in-stream disturbances associated with coal mining, including excess spoil valley fills and refuse impoundments. The plaintiffs sought to enjoin the prospective approval of these nationwide permits and to enjoin some coal operators from additional use of existing nationwide permit approvals until they obtain more detailed individual permits. On July 8, 2004, the court issued an order enjoining the further issuance of Nationwide 21 permits and rescinded certain listed permits where construction of valley fills and surface impoundments had not commenced. On August 13, 2004, the court extended the ruling to all Nationwide 21 permits within the Southern District of West Virginia. The COE appealed the decision to the United States Court of Appeals for the Fourth Circuit. In November 2005, the Fourth Circuit Court of Appeals overturned the July 2004 decision, thereby allowing the continued use of the NWP 21 permitting process, but remanded remaining challenges to the NWP 21 to the district court. Resolution of those additional challenges is still pending before that court. A similar challenge to the Nationwide 21 and related permit processes was filed in Kentucky. Although we have no current operations in Kentucky, similar suits may be filed in other jurisdictions where we do operate.

The Clean Water Act requires that all of our operations obtain NPDES permits for discharges of water from all of our mining operations. All NPDES permits require regular monitoring and reporting of one or more parameters on all discharges from permitted outfalls. When a water discharge occurs and one or more parameters are outside the approved limits permitted in an NPDES permit, these exceedances of permit limits are voluntarily reported to the pertinent agency. The agency may impose penalties for each such release in excess of permitted amounts. If factors such as heavy rains or geologic conditions cause persistent releases in excess of amounts allowed under NPDES permits, costs of compliance can be material, fines may be imposed, or operations may have to be idled until remedial actions are possible.

Recently, there have been renewed efforts by USEPA to examine the coal industry's record of compliance with these limits. That enhanced scrutiny recently resulted in an agreement by one coal operator to pay a $20 million penalty for over 4,000 alleged NPDES permit violations. Subsequently, each of our operating subsidiaries conducted an assessment of their NPDES monitoring and reporting practices, which identified some exceedances of permit limits. In 2008, each of the Company's West Virginia subsidiaries entered into Consent Orders with the West Virginia Department of Environmental Protection on this matter. Fines which in the aggregate totaled less than $300,000 were paid. Future exceedances of permit limits may be unavoidable and future fines may be imposed.

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

Federal and state laws and regulations can also impose measures to be taken to minimize and\or avoid altogether stream impacts caused by both surface and underground mining. Temporary stream impacts from mining are not uncommon, but when such impacts occur there are procedures we follow to remedy any such impacts. These procedures have generally been effective and we work closely with applicable agencies to implement them. Our inability to remedy any temporary stream impacts in the future, and the application of existing or new laws and regulations to disallow any stream impacts, could adversely affect our operating and financial results.

Endangered Species Act

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

Resource Conservation and Recovery Act

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

Subtitle C of 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 a 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion wastes generated at electric utility and independent power producing facilities, such as coal ash. In May 2000, the EPA concluded that coal combustion wastes do not warrant regulation as hazardous under RCRA. The EPA is retaining the hazardous waste exemption for these wastes. However, the EPA has determined that national non-hazardous waste regulations under RCRA Subtitle D are needed for coal combustion wastes disposed in surface impoundments and landfills and used as mine-fill. The agency also concluded 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. Most state hazardous waste laws also exempt coal combustion waste, and instead treat it as either a solid waste or a special waste. Any costs associated with handling or disposal of coal construction wastes as hazardous wastes would increase our customers' operating costs and potentially reduce their demand for coal. In addition, contamination caused by the past disposal of ash can lead to material liability which could reduce demand for coal.

Federal and State Superfund Statutes

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

Additional Information

We file annual, quarterly and current reports, amendments to these reports, proxy statements and other information with the United States Securities and Exchange Commission ("SEC"). You may access and read our SEC filings through our website, at *www.foundationcoal.com*, or the SEC's website at *www.sec.gov*. All documents we file are also available at the SEC's public reference room located at 100 F Street, N.E., Washington, D.C. 20549.

GLOSSARY OF SELECTED TERMS

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

Assigned reserves. Coal that is planned to be mined at an operation that is currently operating, currently idled, or for which permits have been submitted and plans are eventually to develop the operation.

Bituminous coal. A common type of coal with moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btus per pound. It is dense and black and often has well-defined bands of bright and dull material.

British thermal unit, or "Btu". A measure of the thermal energy required to raise the temperature of one pound of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

Central Appalachia. Coal producing area in eastern Kentucky, Virginia, southern West Virginia and a portion of eastern Tennessee.

Clean Air Act Amendments. A comprehensive set of amendments to the federal law governing the nation's air quality. The Clean Air Act was originally passed in 1970 to address significant air pollution problems in our cities. The 1990 amendments broadened and strengthened the original law to address specific problems such as acid deposition, urban smog, hazardous air pollutants and stratospheric ozone depletion.

Coal seam. Coal deposits occur in layers. Each layer is called a "seam."

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

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

Continuous miner. A machine which constantly extracts coal while loading. This is to be distinguished from a conventional mining unit which must stop the extraction process in order for loading to commence.

Continuous mining. Any coal mining process which tears the coal from the face mechanically and loads continuously, thus eliminating the separate cycles of cutting, drilling, shooting and loading. This is to be distinguished from conventional mining, an older process in which these operations are cyclical.

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

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

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

Lignite. The lowest rank of coal with a high moisture content of up to 45% by weight and heating value of 6,500 to 8,300 Btus per pound. It is brownish black and tends to oxidize and disintegrate when exposed to air.

Longwall mining. The most productive underground mining method in the United States. A rotating drum is trammed mechanically across the face of coal, and a hydraulic system supports the roof of the mine while the drum advances through the coal. Chain conveyors then move the loosened coal to a standard underground mine conveyor system for delivery to the surface.

Low Btu coal. Coal which has an average heat content of 9,500 Btus per pound or less.

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

Medium sulfur coal. Coal which, when burned, emits between 1.6 and 4.5 pounds of sulfur dioxide per million Btu.

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

Mid Btu coal. Coal which has an average heat content of between 9,500 and 12,500 Btus per pound.

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

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

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

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

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

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

Probable reserves. Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

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 process of restoring land and the environment to their original state following mining activities. The process commonly includes "recontouring" or reshaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers. Reclamation operations are usually underway before the mining of a particular site is completed. Reclamation is closely regulated by both state and federal law.

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

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

Room-and-Pillar Mining. Method of underground mining in which the mine roof is supported mainly by coal pillars left at regular intervals. Rooms are placed where the coal is mined.

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

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

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

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

Surface mine. A mine in which the coal lies near the surface and can be extracted by removing the covering layer of soil (see "Overburden"). About 67% of total U.S. coal production comes from surface mines.

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

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

Unassigned reserves. Coal that is likely to be mined in the future, but which is not considered *Assigned reserves.*

Underground mine. Also known as a "deep" mine. Usually located several hundred feet below the earth's surface, an underground mine's coal is removed mechanically and transferred by shuttle car and conveyor to the surface. Underground mines account for about 33% of annual U.S. coal production.

Unit train. A train of 100 or more cars carrying a single product. A typical coal unit train can carry at least 10,000 tons of coal in a single shipment.

ITEM 1A. RISK FACTORS.

RISK FACTORS

Risks Relating to Our Business

A substantial or extended decline in coal prices or demand could reduce our revenues and the value of our coal reserves.

The prices we charge for coal depend upon factors beyond our control, including, but not limited to:

- the supply of, and demand for, domestic and foreign coal due to weather or other factors;
- the demand for electricity;
- domestic and foreign demand for steel and the continued financial viability of the domestic and/or foreign steel industry;
- the proximity to, capacity of, and cost of transportation facilities;
- domestic and foreign governmental regulations and taxes;
- air emission and other regulatory standards for coal-fired power plants and industrial facilities;
- costs of transportation of our coal relative to our competitors;
- regulatory, administrative and court decisions;
- the price and availability of alternative fuels, including the effects of technological developments;
- the effect of worldwide energy conservation measures;
- disruptions in delivery or changes in pricing from third party vendors of goods and services which are necessary for our operations, such as fuel, steel products, explosives and tires; and
- domestic and international economic conditions.

Our results of operations are dependent upon the prices we charge for our coal as well as our ability to improve productivity and control costs. Any decreased demand would cause spot prices to decline and require us to increase productivity and decrease costs in order to maintain our margins. If we are not able to maintain our margins, our operating results could be adversely affected. Therefore, price declines may adversely affect operating results for future periods and our ability to generate cash flows necessary to improve productivity and invest in operations.

Changes in market conditions, factors influencing the demand for coal, and increased production costs could adversely affect our revenues.

Continued demand for our coal, most of which is sold to plants in North America, and the prices that we will be able to obtain could be adversely affected by factors such as changes in coal consumption patterns. Consumption by the domestic utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel supplies including nuclear, natural gas, oil and renewable energy sources. Many of the recently constructed electric power sources have been gas-fired, by virtue of lower construction costs and reduced environmental risks. Gas-based generation from existing and newly constructed gas-based facilities has the potential to displace coal-based generation, particularly from older, less efficient coal generators. In addition, the increasingly stringent requirements of the Clean Air Interstate Rule, or "CAIR" and Clean Air Mercury Rule, or "CAMR", Rule may result in more electric power generators shifting from coal to natural gas-fired power plants. Any reduction in coal demand from the electric generation and steel sectors could create short-term market imbalances, leading to lower demand for, and price of, our products, thereby reducing our revenue. Higher costs for transporting coal also can have a detrimental impact on coal market demand. Our results are highly dependent upon the prices we receive for our coal. Decreased demand for coal, both domestically and internationally, could cause spot prices and the prices we are able to negotiate on long-term contracts to decline. The lower prices could negatively affect our cash flows, results of operations or financial condition, if we are unable to increase productivity and/or decrease costs in order to maintain our margins. Our revenues also may be adversely affected if production cost increases, including higher costs for labor, materials and equipment, outpace coal market price increases or erode our margins for coal sold under long-term coal supply agreements with pre-determined pricing.

Our profitability may decline due to unanticipated mine operating conditions and other factors that are not within our control.

Our mining operations are influenced by changing conditions that can affect production levels and costs at particular mines for varying lengths of time and as a result can diminish our profitability. Weather conditions, equipment and parts availability, replacement or repair of equipment, prices and availability for fuel, steel, explosives, tires and other supplies, fires, variations in thickness of the layer, or seam, of coal, amounts of overburden partings, rock and other natural materials, accidental mine water discharges and other geological conditions have had, and can be expected in the future to have, a significant impact on our operating results.

Decreases in our profitability as a result of the factors described above could materially adversely impact our quarterly or annual results. These risks may not be covered by our insurance policies.

MSHA and state regulators may order certain of our mines to be temporarily closed or operations therein modified, which would adversely affect our ability to meet our contracts or projected costs.

MSHA and state regulators may order certain of our mines to be temporarily closed due to an investigation of an accident resulting in property damage or injuries, or due to other incidents such as fires, roof falls, water flow, equipment failure or ventilation concerns. In addition, regulators may order changes to mine plans or operations due to their interpretation or application of existing or new laws or regulations. Any required changes to mine plans or operations may result in temporary idling of production or addition of costs.

Our profitability may be adversely affected by the status of our long-term coal supply contracts, and changes in purchasing patterns in the coal industry may make it difficult for us to extend existing contracts or enter into long-term supply contracts, which could adversely affect the capability and profitability of our operations.

We sell a significant portion of our coal under long-term coal supply agreements, which we define as contracts with a term greater than 12 months. The prices for coal shipped under these contracts are set, although sometimes subject to adjustment, and thus may be below the current market price for similar-type coal at any given time. As a consequence of the substantial volume of our sales that are subject to these long-term agreements, we have less coal available with which to capitalize on higher coal prices if and when they arise. In addition, in some cases, our ability to realize the higher prices that may be available in the spot market may be restricted when customers elect to purchase higher volumes allowable under some contracts. Conversely, when the prices in our long-term coal supply contracts are significantly higher than prices in the spot market, customers may seek to renegotiate their contractual commitment to purchase the higher priced coal, which could result in an amended contract or in litigation, the outcome of which is uncertain. In such situations, we may elect to renegotiate such contracts for business reasons and capture the contract's value in differing ways.

When our current contracts with customers expire or are otherwise renegotiated, our customers may decide not to extend or enter into new long-term contracts or, in the absence of long-term contracts, our customers may decide to purchase fewer tons of coal than in the past or on different terms, including under different pricing terms. For additional information relating to these contracts, see "Business—Long-Term Coal Supply Agreements".

As electric utilities continue to adjust to the regulations of the Clean Air Act, the CAIR, the regulation of mercury, possible regulation of greenhouse gas emissions and other regulatory changes with respect to plant emissions, and the possible deregulation of their industry, they could become increasingly less willing to enter into long-term coal supply contracts and instead may purchase higher percentages of coal under short-term supply contracts. To the extent the industry shifts away from long-term supply contracts, it could adversely affect us and the level of our revenues. For example, fewer electric utilities will have a contractual obligation to purchase coal from us, thereby increasing the risk that we will not have a market for our production. Furthermore, spot market prices tend to be more volatile than contractual prices, which could result in decreased or less predictable revenues.

Certain provisions in our supply contracts may result in economic penalties upon the failure to meet specifications.

Most of our coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, hardness and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or, in the extreme, termination of the contracts. With respect to sulfur, the price of SO_2 allowances in the market is sometimes used to adjust the price we receive for coal and the market price for these allowances fluctuate and thus may cause us not to receive the anticipated revenues.

Consequently, due to the risks mentioned above with respect to long-term contracts, we may not achieve the revenue or profit we expect to achieve from these sales commitments.

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

We derived 55% of our total coal revenues from sales to our 10 largest customers for the year ended December 31, 2008, with the largest customer accounting for approximately 16% of our coal revenues for that year. At December 31, 2008, we had coal supply agreements with those 10 customers that expire at various times from 2009 to 2020. Negotiations to extend existing agreements or enter into new long-term agreements with those and other customers may not be successful, and those customers may not continue to purchase coal from us under long-term coal supply agreements, or at all. If any of our top customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our revenues and profitability could suffer materially.

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

In addition to marketing coal that is produced from our controlled reserves, we purchase and resell coal produced by third parties from their controlled reserves to meet customer specifications and, in certain circumstances, we also at times utilize contractors to operate our mines or loading facilities. Disruption in our supply of third-party coal and contractor-produced coal could temporarily impair our ability to fill our customers' orders or require us to pay higher prices in order to obtain the required coal from other sources. Operational difficulties at contractor-operated mines, 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 by contractors for us. Any increase in the prices we pay for third-party coal or contractor-produced coal could increase our costs and therefore lower our earnings.

Competition within the coal industry may adversely affect our ability to sell coal.

Coal with lower production costs shipped east from Western coal mines and from offshore sources has resulted in increased competition for coal sales in the Eastern United States. This competition could result in a decrease in our market share in this region and a decrease in our revenues.

Demand for our higher sulfur coal and the price that we can obtain for it is impacted by, among other things, the changing laws with respect to allowable emissions and the price of emission allowances. Significant increases in the price of those allowances could reduce the competitiveness of higher sulfur coal at plants not equipped to reduce sulfur dioxide emissions. Competition from low sulfur coal and possibly natural gas could result in a decrease in the higher-sulfur coal market share and revenues from some of our operations.

Overcapacity in the coal industry, both domestically and internationally, may affect the price we receive for our coal. For example, in the past, increased demand for coal and attractive pricing brought new investors to the coal industry and promoted the development of new mines. These factors resulted in added production capacity throughout the industry, which led to increased competition and lower coal prices. Continued coal pricing at relatively high levels, compared to historical levels, could encourage the development of expanded capacity by new or existing coal producers. Any overcapacity could reduce coal prices in the future.

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

The government extensively regulates our mining operations, which imposes significant actual and potential costs on us, and future regulations could increase those costs or limit our ability to produce coal.

Our operations are subject to a variety of federal, state and local environmental, health and safety, transportation, labor and other laws and regulations. Examples include those relating to employee health and safety; emissions to air and discharges to water; plant and wildlife protection; the reclamation and restoration of properties after mining or other activity has been completed; the storage, treatment and disposal of wastes; remediation of contaminated soil, surface and groundwater; surface subsidence from underground mining; noise; and the effects of operations on surface water and groundwater quality and availability. In addition, we are subject to significant legislation mandating certain benefits for current and retired coal miners. We incur substantial costs to comply with government laws and regulations that apply to our mining and other operations.

Numerous governmental permits and approvals are required under these laws and regulations for mining and other operations. Many of our permits are subject to renewal from time to time, and renewed permits may contain more restrictive conditions than our existing permits. Many of our permits governing discharges to or impacts upon surface streams and groundwater will be subject to new and more stringent conditions to address various new water quality requirements that permitting authorities are now required to address when those permits are renewed over the next several years. To obtain new permits we may have to petition to have stream quality designations changed based on available data, and if we are unsuccessful we may not be able to operate the planned facility or to operate as planned. Although we have no estimates at this time, our costs to satisfy such conditions could be substantial. We may also be required under certain permits to provide authorities data pertaining to the effect or impact that a proposed exploration for or production of coal may have on the environment. In recent years, the permitting required under the Clean Water Act to address filling streams and other valleys with wastes from mountaintop coal mining operations and preparation plant refuse disposal has been the subject of extensive litigation by environmental groups against coal mining companies and environmental regulatory authorities, as well as regulatory changes by legislative initiatives in the U.S. Congress. It is unclear at this time how the issues will ultimately be resolved, but for this as well as other issues that may arise involving permits necessary for coal mining and other operation, such requirements could prove costly and time-consuming, and could delay commencing or continuing exploration or production operations. New laws and regulations, as well as future interpretations or different enforcement of existing laws and regulations, may require substantial increases in equipment and operating costs to us and delays, interruptions or a termination of operations, the extent of which we cannot predict.

Because of extensive and comprehensive regulatory requirements, violations of laws, regulations and permits occur at our operations from time to time and may result in significant costs to us to correct such violations, as well as civil or criminal penalties and limitations or shutdowns of our operations.

Extensive regulation of these matters has had and will continue to have a significant effect on our costs of production and competitive position. Further regulations, legislation or enforcement may also cause our sales or profitability to decline by hindering our ability to continue our mining operations, by increasing our costs or by causing coal to become a less attractive fuel source. See "Business—Environmental and Other Regulatory Matters" for a discussion of some of the environmental and other regulations affecting our business.

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

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

Our operations can also impact flows and water quality in surface water bodies and remedial measures may be required, such as grouting cracks or lining of stream beds, to prevent or minimize such impacts. We are currently involved with state environmental authorities concerning impacts or alleged impacts of our mining operations on water flows in several surface streams. We are studying, or addressing, those impacts and we have not finally resolved those matters. Many of our mining operations take place in the vicinity of streams, and similar impacts could be asserted or identified at other streams in the future. The costs of our efforts at the streams we are currently addressing, and at any other streams that may be identified in the future, could be significant. Our mining and oil and gas operations also generate water which we need to collect and dispose of or treat. In the past we have sometimes disposed of this water in mined out areas or in permitted refuse impoundments. If we are unable to obtain permits for this type of water disposal in the future our costs to operate may increase substantially.

We maintain extensive coal slurry impoundments at a number of our mines. Such impoundments are subject to regulation. Slurry impoundments maintained by other coal mining operations have been known to fail, releasing large volumes of coal slurry. Structural failure of an impoundment can result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. We have commenced measures to modify our method of operation at one surface impoundment containing slurry wastes in order to reduce the risk of releases to the environment from it, a process that will take several years to complete. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental contamination and associated liability, as well as for fines and penalties. The level of insurance we carry to cover exposures for this type or occurrence and other unanticipated events may not be adequate.

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

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

The Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. Such regulations may require significant emissions control expenditures for existing and new coal-fired power plants to attain applicable ambient air quality standards. In addition, state regulatory schemes for electricity pricing may be administered to not permit recovery of investments in emissions control equipment. As a result, these generators may switch to fuels that generate less of these emissions, possibly reducing the likelihood that generators will keep existing coal-fired power plants in service or build new coal-fired power plants. Any of these developments may reduce demand for our coal.

For example, the final CAIR was issued by the EPA in 2005. The rule calls for power plants in Texas and 27 states bordering or east of the Mississippi River, and the District of Columbia, to reduce emission levels of sulfur dioxide and nitrous oxide. At full implementation, CAIR is estimated by the EPA to cut regional sulfur dioxide emissions by more than 70% from the 2003 levels, and to cut nitrogen oxide emissions by more then 60% from 2003 levels. States must achieve the required emission reductions using one of two compliance options. The first alternative is for the state to require power plants to participate in an EPA administered "cap-and-trade" system that caps emissions in two stages. This cap and trade approach is similar to the system now in effect under other regulations controlling air pollution. Alternatively, a state can elect to meet a specific state emissions budget through measures of the state's choosing. These state measures will be at least as stringent as those imposed by CAIR. The stringency of the caps may require many coal-fired sources to install additional pollution control equipment to comply. This increased sulfur emission removal capability caused by the proposed rule could result in decreased demand for low sulfur coal, potentially driving down prices for low sulfur coal. After the passage of CAIR, different entities and organizations challenged the rule on various bases. The U.S. Court of Appeals for the D.C. Circuit (*State of North Carolina, et al. v. EPA*, No. 05-1244) on July 11, 2008 issued its decision in litigation challenging CAIR. The decision vacated CAIR and the CAIR federal implementation plan in their entirety. The decision remanded CAIR to EPA to promulgate a rule that complies with the court's opinion. The court ruled against the EPA on several of the core aspects of the rule, including: CAIR's use of unrestricted interstate trading; the 2015 compliance deadline for Phase 2 of CAIR; the use of Title IV allowances at a heightened surrender ratio for compliance with the SO_2 part of CAIR; and EPA's determination of the SO_2 and NOx emission budgets. The court also struck down emission allowance trading in CAIR, holding that unrestricted trading might result in no emission reductions in an upwind state, thereby preventing the EPA from fulfilling its responsibility under the Clean Air Act to prohibit sources in one state from contributing to non-attainment in another state. Ultimately, this ruling may significantly impact the EPA's potential future ability to address interstate pollution transport with a cap-and-trade system. The court also rejected an EPA "fairness" argument and ruled that it was inappropriate for the EPA to divide a region wide NOx budget among the states, and essentially remove each state's responsibility to eliminate its own significant contribution to downwind pollution. After this ruling, later in 2008 the EPA petitioned the court for a rehearing. After briefing by all parties, in December 2008 the court ruled that a complete vacatur of the rule would sacrifice clear benefits to public health and the environment while the EPA works to fix the deficiencies found by the court. Thus CAIR will be in effect while the EPA modifies the rule. How the EPA will proceed to modify CAIR is uncertain at this time.

In 2005, the EPA finalized a CAMR for controlling mercury emissions from power plants by imposing a two-step approach to reducing, between now and 2018, the total mercury emissions allowed from coal-fired power plants nationwide. The approach adopted sets a mandatory, declining cap on the total mercury emissions allowed from coal-fired power plants nationwide. This "cap-and-trade" approach is similar to the approach under the CAIR rule discussed above. This approach, which allows mercury emissions trading, when combined with the CAIR regulations, will reduce mercury emissions by nearly 70% from current levels once facilities reach a final mercury cap which takes effect in 2018. Current mercury emissions from United States power plants are about 48 tons per year. The first phase cap is 38 tons beginning in 2010. EPA estimates that much of this reduction will come as a "co-benefit" of the pollution control devices installed under the CAIR regulations. The final cap is set at 15 tons per year beginning in 2018. Each state has been allocated a budget of mercury emissions and must submit a plan on meeting its budget for mercury reductions. The states are not required to adopt the cap-and-trade approach, but many took that approach. Alternatively, a state can elect to meet a specific state emissions budget through measures of the state's choosing. On February 8, 2008, the United States Court of Appeals for the District of Columbia Circuit struck down the EPA's regulations for reducing mercury emissions from coal-fired power plants. The effect of the court's ruling is to maintain power plants on the list of hazardous air pollutant sources subject to regulation under section 112 of the Clean Air Act and to invalidate the EPA's "cap-and-trade" approach to regulation of mercury emissions. Both the EPA and industry appealed the decision to the United States Supreme Court after the lower court denied a petition for rehearing. In February 2009 the EPA announced it would withdraw this appeal and proceed to draft regulations for use of "maximum achievable control technologies", or "MACT" under section 112 of the Clean Air Act, and if the United States Supreme Court declined to rehear the case. The EPA rulemaking process will likely take several years. After a rule is issued, affected utilities would have three years to comply with the standard. Separate state standards may also be passed and applied in the interim. A MACT standard could increase the cost of consuming coal and impact the demand for coals with various amounts or compounds of mercury contained therein.

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

Current and future proposals may be introduced in Congress and various states designed to further reduce emissions of sulfur dioxide, nitrogen oxides and mercury from power plants, and certain ones could regulate additional emissions such as carbon dioxide. If such initiatives are enacted into law, power plant operators could choose other fuel sources to meet their requirements, thereby reducing the demand for coal. Current and possible future governmental programs are or may be in place to require the purchase and trading of allowances associated with the emission of various substances such as sulfur dioxide, nitrous oxide, mercury and carbon dioxide. Changes in the markets for and prices of allowances could have a material effect on demand for and prices received for our coal.

The United States and more than 160 other nations are signatories to the 1992 United Nations Framework Convention on Climate Change, which is intended to limit emissions of greenhouse gases, such as carbon dioxide which is a major by-product of burning coal. In December 1997, in Kyoto, Japan, the signatories to the convention agreed to the Kyoto Protocol (the "Protocol") which is a binding set of emission targets for developed nations. Although the specific emission targets vary from country to country, if the United States were to ratify the Protocol, our nation would be required to reduce emissions to 93% of 1990 levels over a five-year period from 2008 through 2012. The United States has not ratified the Protocol. The Protocol which expires in 2012 has received sufficient support from enough nations to enter into force and will become binding on all those countries that have ratified it.

As part of the United Nations Framework Convention on Climate Change, representatives from 187 nations met in Bali, Indonesia in December 2007 to discuss a program to limit greenhouse gas emissions after 2012. The United States participated in the conference. The convention adopted what is called the "Bali Action Plan." The Bali Action Plan contains no binding commitments, but concludes that "deep cuts in global emissions will be required" and provides a timetable for two years of talks to shape the first formal addendum to the 1992 United Nations Framework Convention on Climate Change treaty since the Kyoto Protocol. The ultimate outcome of the Bali Action Plan, and any treaty or other arrangement ultimately adopted by the United States or other countries, may have a material adverse impact the global supply and demand for coal and the costs to consume coal and conduct our operations. This is particularly true if cost effective technology for the capture and sequestration of carbon dioxide is not sufficiently developed.

Although the Protocol is still not binding on the United States and the Bali Action Plan is just commencing, and because no comprehensive regulations focusing on greenhouse gas emissions are in place, these restrictions, whether through ratification of global agreements or other efforts to stabilize or reduce greenhouse gas emissions, could adversely affect the price and demand for coal. Countries that have to reduce emissions may use less coal affecting demand for United States export coal. There could be pressure on companies in the United States to reduce emissions if they want to trade with countries that are part of the Protocol or subsequent global agreements. From time to time Congress may consider various proposals to tax or otherwise limit greenhouse gas emissions. In addition, some states and municipalities in the United States have adopted or may adopt in the future regulations on greenhouse gas emissions. Some states and municipal entities have commenced litigation in different jurisdictions seeking to have certain utilities, including some of our customers, reduce their emission of carbon dioxide. If successful, there could be limitation on the amount of coal our customers could utilize. Any of these measures could affect coal demand at utilities in the United States. See "Business—Environmental and Other Regulatory Matters" for a discussion of some of the environmental and other regulations affecting our business.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce revenues by causing us to reduce our production or impairing our ability to supply coal to our customers.

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

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

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

Because our profitability is substantially dependent on the availability of an adequate supply of coal reserves that can be mined at competitive costs, the unavailability of these types of reserves would cause our profitability to decline.

We have not yet applied for all of the permits required, or developed the mines necessary, to use all of our reserves. Furthermore, we may not be able to mine all of our reserves as profitably as we do at our current operations. Our planned development projects and acquisition activities may not result in significant additional reserves and we may not have continuing success developing new mines or expanding existing mines beyond our existing reserves. Most of our mining operations are conducted on properties owned or leased by us. Because title to most of our leased properties and mineral rights is not thoroughly verified until a permit to mine the property is obtained, our right to mine some of our reserves may be materially adversely affected if defects in title or boundaries exist. In addition, in order to develop our reserves, we must receive various governmental permits. We may be unable to obtain the permits necessary for us to operate profitably in the future. Some of these permits are becoming increasingly more difficult and expensive to obtain and the review process continues to lengthen.

Our profitability depends substantially on our ability to mine coal reserves that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Replacement reserves may not be available when required or, if available, may not be capable of being mined at costs comparable to those characteristic of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves that we now own or subsequently acquire, which may adversely affect our profitability and financial condition. Exhaustion of reserves at particular mines also may have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves through acquisitions in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates or the inability to acquire coal properties on commercially reasonable terms.

We face numerous uncertainties in estimating our economically recoverable coal reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs or decreased profitability.

We base our reserve information on engineering, economic and geological data assembled and analyzed by our staff, which includes various engineers and geologists, and which is periodically reviewed by outside firms. The reserve estimates as to both quantity and quality are annually updated to reflect production of coal from the reserves and new drilling, engineering or other data received. There are numerous uncertainties inherent in estimating quantities and qualities of and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves and net cash flows necessarily depend upon a number of variable factors and assumptions, such as geological and mining conditions which may not be fully identified by available exploration data or which may differ from experience in current operations, historical production from the area compared with production from other similar producing areas, the assumed effects of regulation and taxes by governmental agencies and assumptions concerning coal prices, operating costs, mining technology improvements, severance and excise tax, development costs and reclamation costs, all of which may vary considerably from actual results.

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

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

We conduct a significant part of our mining operations on properties that we lease. A title defect or the loss of any lease could adversely affect our ability to mine the associated reserves. In addition, from time to time the rights of third parties for competing uses of adjacent, overlying, or underlying lands such as for oil and gas activity, coalbed methane, production, pipelines, roads, easements and public facilities may affect our ability to operate as planned if our title is not superior or arrangements cannot be negotiated. Title to much of our leased properties and fee mineral rights is not usually verified until we make a commitment to develop a property, which may not occur until after we have obtained necessary permits and completed exploration of the property. Our right to mine some of our reserves has in the past been, and may again in the future be, adversely affected if defects in title or boundaries exist or competing interests cannot be resolved. In order to obtain leases or other rights to conduct our mining operations on property where these defects exist, we may in the future have to incur unanticipated costs or leave un-mined the affected reserves. In addition, we may not be able to successfully purchase or negotiate new leases for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease.

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

Our strategy includes opportunistically expanding our operations and mineral reserves through acquisitions of businesses and assets, mergers, joint ventures or other transactions. Such transactions involve various inherent risks, such as:

- uncertainties in assessing the value, strengths and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of, acquisition or other transaction candidates;
- the potential loss of key customers, management and employees of an acquired business;
- the inability to achieve identified operating and financial synergies anticipated to result from an acquisition or other transaction;
- problems that could arise from the integration of the acquired business; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying the acquisition or other transaction rationale.

Any one or more of these and other factors could cause us not to realize the benefits anticipated to result from the acquisition of businesses or assets or could result in unexpected liabilities associated with the acquired businesses.

Expenditures for benefits for non-active employees could be materially higher than we have anticipated, which could increase our costs and adversely affect our financial results.

We are responsible for certain long-term liabilities under a variety of benefit plans and other arrangements with active and inactive employees. The unfunded status (the excess of projected benefit obligation over plan assets) of these obligations, as reflected in Note 13 to our consolidated financial statements at December 31, 2008, included $557.6 million of postretirement obligations, $116.0 million of defined benefit pension obligations, $32.3 million of workers' compensation obligations and $20.8 million of self-insured pneumoconiosis obligations. These obligations have been estimated based on assumptions including actuarial estimates, assumed discount rates, estimates of mine lives, expected returns on pension plan assets and changes in health care costs. We could be required to expend greater amounts than anticipated. In addition, future regulatory and accounting changes relating to these benefits could result in increased obligations or additional costs, which could also have a material adverse affect on our financial results. Several states in which we operate consider changes in workers' compensation laws from time to time, which, if enacted, could adversely affect us.

The inability of the sellers of companies we have acquired to fulfill their indemnification obligations to us under our acquisition agreements could increase our liabilities and adversely affect our results of operations and financial position.

In our acquisition and disposition agreements, the respective sellers and buyers, and in some cases, their parent companies, agreed to retain responsibility for and indemnify us against damages resulting from certain third-party claims or other liabilities. These third-party claims and other liabilities include, without limitation, employee liabilities, costs associated with various litigation matters related to the mines involved, and certain environmental liabilities. The failure of any seller or buyer and, if applicable, its parent company, to satisfy its obligations with respect to claims and retained liabilities covered by the relevant agreements could have an adverse effect on our results of operations and financial position because claimants may successfully assert that we are liable for those claims and/or retained liabilities. In addition, certain obligations of the sellers to indemnify us will terminate or have already terminated upon expiration of the applicable indemnification period and will not cover damages in excess of the applicable indemnity coverage limit. The assertion of third-party claims after the expiration of the applicable indemnification period or in excess of the applicable coverage limit, or the failure of any seller to satisfy its indemnification obligations with respect to breaches of its representations and warranties, could have an adverse effect on our results of operations and financial position.

Our leverage could harm our business by limiting our available cash and our access to additional capital, and could force us to sell material assets or operations to attempt to meet our debt service obligations.

Our financial performance could be affected by our indebtedness. As of December 31, 2008, our total indebtedness was $599.8 million. In addition, as of December 31, 2008, we had $170.9 million of letters of credit outstanding and additional borrowings available under our revolving credit facility of $329.1 million. We may also incur additional indebtedness in the future.

The degree to which we are leveraged could have important consequences, including, but not limited to:

- making it more difficult to self-insure and obtain surety bonds or letters of credit;
- limiting our ability to enter into new long-term sales contracts;
- increasing our vulnerability to general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of our cash flow from operations to the payment of principal of, and interest on, our indebtedness, thereby reducing the availability of the cash flow to fund working capital, capital expenditures, research and development or other general corporate uses;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, research and development, debt service requirements or other general corporate requirements;
- making it more difficult for us to pay interest and satisfy our debt obligations;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

In addition, our indebtedness subjects us to financial and other restrictive covenants. Failure by us to comply with these covenants could result in an event of default which, if not cured or waived, could have a material adverse effect on us. Furthermore, substantially all of our material assets secure our indebtedness under our Senior Secured Credit Facility.

If our cash flows and capital resources are insufficient to fund our debt service obligations or our requirements under our other long-term liabilities, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations or our requirements under our other long term liabilities. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our Senior Secured Credit Facility and the indenture under which our 7.25% Senior Notes were issued restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

If our business does not generate sufficient cash from operations, we may not be able to repay our indebtedness.

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

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

Despite our current leverage, we may still be able to incur substantially more debt. This could further exacerbate the risks associated with our indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of our indebtedness do not prohibit Foundation Coal Holdings, Inc. or our subsidiaries from doing so. If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

The covenants in our Senior Secured Credit Facility and our indenture impose restrictions that may limit our operating and financial flexibility.

The Senior Secured Credit Facility, our indenture governing the 7.25% Senior Notes and the instruments governing our other indebtedness contain a number of significant restrictions and covenants that limit the ability of our subsidiaries to enter into certain financial arrangements or engage in specified transactions, including the payment of certain dividends.

Operating results below current levels or other adverse factors, including a significant increase in interest rates, could result in our being unable to comply with our financial covenants contained in our Senior Secured Credit Facility. If we violate these covenants and are unable to obtain waivers from our lenders, our debt under these agreements would be in default and could be accelerated by our lenders. If our indebtedness is accelerated, we may not be able to repay our debt or borrow sufficient funds to refinance it. Even if we are able to obtain new financing, it may not be on commercially reasonable terms, on terms that are acceptable to us or at all. If our debt is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected. In addition, complying with these covenants may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.

Failure to maintain required surety bonds could affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease the coal. Failure to maintain capacity for required letters of credit could limit our available borrowing capacity under our Senior Secured Credit Facility and could negatively impact our ability to obtain additional financing to fund future working capital, capital expenditures or other general corporate requirements.

We are required to provide financial assurance to secure our obligations to reclaim lands used for mining, to secure payment of federal and state workers' compensation and pneumoconiosis benefits, to secure coal lease obligations and to satisfy other miscellaneous obligations. We generally use surety bonds to secure reclamation and coal lease obligations. We generally use letters of credit to assure workers' compensation benefits, UMWA retiree medical benefits and as collateral for surety bonds. Miscellaneous obligations are secured using both surety bonds and letters of credit.

As of December 31, 2008, we had outstanding surety bonds of $300.3 million, which includes $275.2 million secured reclamation obligations; $15.7 million secured coal lease obligations; $7.1 million secured self-insured workers' compensation obligations; and $2.3 million secured miscellaneous obligations. The premium rates and terms of the surety bonds are subject to annual renewals. It has become increasingly difficult for us to secure new surety bonds or renew bonds without the posting of partial collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal law would affect our ability to secure reclamation and coal lease obligations, which could adversely affect our ability to mine or lease the coal. That failure could result from a variety of factors including the following:

- lack of availability, higher expense or unfavorable market terms of new surety bonds; and
- restrictions on the availability of collateral for current and future third-party surety bond issuers under the terms of the indenture or new credit facilities.

In addition, as of December 31, 2008, we had $170.9 million of letters of credit in place for the following purposes: $39.1 million for workers' compensation, including collateral for workers' compensation bonds; $8.1 million for UMWA retiree health care obligations; $117.1 million related to collateral for reclamation surety bonds; and $6.6 million for other miscellaneous obligations. Obligations secured by letters of credit may increase in the future. Any such increase would limit our available borrowing capacity under the Senior Secured Credit Facility and could negatively impact our ability to obtain additional financing to fund future working capital, capital expenditures or other general corporate requirements.

Due to our participation in multi-employer pension plans, we may have exposure under those plans that extend beyond what our obligation would be with respect to our employees.

We contribute to two multi-employer defined benefit pension plans administered by the UMWA. In 2008, our total contributions to these plans and other contractual payments under our UMWA wage agreement were approximately $14.1 million.

In the event of a partial or complete withdrawal by us from any plan which is underfunded, we would be liable for a proportionate share of such plan's unfunded vested benefits. Based on the information available from plan administrators, we believe that our portion of the contingent liability in the case of a full withdrawal or termination would be material to our financial position and results of operations. In the event that any other contributing employer withdraws from any plan which is underfunded, and such employer (or any member in its controlled group) cannot satisfy its obligations under the plan at the time of withdrawal, then we, along with the other remaining contributing employers, would be liable for our proportionate share of such plan's unfunded vested benefits.

The Pension Protection Act of 2006 ("Pension Act") requires a minimum funding ratio of 80% be maintained for this multi-employer pension plan and if the plan is determined to have a funding ratio of less than 80%, it will be deemed to be "endangered", and if less than 60% it will deemed to be "critical", and will in either case be subject to additional funding requirements. Based on an estimated funding percentage of 91.4%, a certification was provided by the multi-employer plan actuary, stating that the plan is in neither "endangered" or "critical" status for the plan year beginning July 1, 2008. However, the current volatile economic environment and the rapid deterioration in equity markets since July 1, 2008 may have caused investment income and the value of investments held in the 1974 Pension Trust to decline and lose value. If a subsequent estimate of the funding ratio performed by the multi-employer plan actuary were to deem the plan to be in "endangered" or "critical" status, such a determination would require certain of our subsidiaries to make additional contributions pursuant to a funding improvement plan implemented in accordance with the Pension Act, and, therefore, could have a material impact on our operating results.

Our pension plans are currently underfunded and we may have to make significant cash payments to the plans, reducing the cash available for our business.

We sponsor pension plans in the United States for salaried and non-union hourly employees. For these plans, the Pension Act requires a funding target of 100% of the present value of accrued benefits. The Pension Act includes a funding target phase-in provision that establishes a funding target of 92% in 2008, 94% in 2009, 96% in 2010 and 100% thereafter for defined benefit pension plans. Generally, any such plan with a funding ratio of less than 80% will be deemed at risk and will be subject to additional funding requirements under the Pension

Act. The current volatile economic environment and the rapid deterioration in the equity markets since July 1, 2008 may have caused investment income and the value of investment assets held in our pension trust to decline and lose value. As a result, we may be required to increase the amount of cash contributions into the pension trust in order to comply with the funding requirements of the Pension Act.

In 2008 we contributed $11.3 million to our pension plans. We currently expect to make contributions in 2009 of approximately $30.0 million to maintain at least an 80% funding ratio.

As of December 31, 2008, our annual measurement date, our pension plans were underfunded by $116.0 million (based on the actuarial assumptions used for Statement of Financial Accounting Standards ("SFAS") No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158"). Our pension plans are subject to the Employee Retirement Income Security Act of 1974 ("ERISA"). Under ERISA, the Pension Benefit Guaranty Corporation, or PBGC, has the authority to terminate an underfunded pension plan under limited circumstances. In the event our U.S. pension plans are terminated for any reason while the plans are underfunded, we will incur a liability to the PBGC that may be equal to the entire amount of the underfunding.

Our financial condition could be negatively affected if we fail to maintain satisfactory labor relations.

As of December 31, 2008, the UMWA represented approximately 34% of our affiliate's employees, who produced approximately 19% of our coal sales volume during the fiscal year ended December 31, 2008. The mines represented by the UMWA include Emerald and Cumberland longwall mines in Pennsylvania. These subsidiaries have distinct collective bargaining agreements. Because of the higher labor costs and the increased risk of strikes and other work-related stoppages that may be associated with union operations in the coal industry, our non-unionized competitors may have a competitive advantage in areas where they compete with unionized operations. If some or all of our current non-union operations were to become unionized, we could incur an increased risk of work stoppages, reduced productivity and higher labor costs. The two existing collective bargaining agreements with the UMWA expire at the end of the fourth quarter of 2011. If the applicable subsidiaries are unable to reach a mutually acceptable replacement agreement, it could adversely affect their productivity, increase their costs and disrupt shipments, or result in the closure of the mine due to a strike by the workers or a lockout by local management.

Wage agreements between three affiliates of the Company and the UMWA expired on or shortly after March 31, 2007. Specifically, the wage agreement for Wabash expired at 11:59 p.m. on March 31, 2007 and the UMWA wage agreements with Cumberland Coal Resources, LP ("Cumberland") and Emerald Coal Resources, LP ("Emerald") expired at 11:59 p.m. on April 1, 2007. Negotiations between these respective subsidiaries and the UMWA commenced in early January of 2007 but intensified in late March of 2007 and continued through April 3, 2007. Emerald and Cumberland reiterated their willingness to sign the 2007 National Bituminous Coal Operators Association ("BCOA") UMWA wage agreement. Wabash would not sign the BCOA agreement. The hourly workforce continued to work without a formal agreement of the parties under the terms of the expired wage agreement until 12:01 a.m. on April 4, 2007 at which time, alleging unfair labor practices by Wabash, Emerald and Cumberland, the UMWA represented hourly workforces went on strike at the Wabash, Emerald and Cumberland mines. Subsequent to the commencement of a UMWA strike on April 4, 2007, Wabash announced the idling of the mine in southern Illinois. The mine had become economically unviable at that time as a result of a combination of factors, including aged infrastructure, softening market conditions and the prospect of a new higher cost labor contract with the UMWA.

On April 10, 2007, negotiations between the UMWA and the three subsidiaries resumed. In the early evening of April 12, 2007, it was announced that the UMWA and the three subsidiaries had reached agreement and that the workforces at Emerald and Cumberland would return to work. Wabash remained idled and the effects of the idling had been negotiated with the UMWA.

In November 2003, the UMWA held an election at our Rockspring mining facility in West Virginia. The UMWA challenged nine unopened ballots as being improperly cast by supervisors. The outcome of the election will depend on the decision of the National Labor Relation Board (the "NLRB") with respect to the nine challenged ballots, which ballots will not be opened until final resolution of the challenge. On February 5, 2004, the Regional Director of the NLRB ruled that only five of the nine challenged ballots could be counted. Both parties appealed to the full NLRB. In 2006, the NLRB ordered five of the nine ballots to be opened. All were votes against the UMWA. This resulted in a revised tally of 110 for UMWA representation and 108 against the UMWA. The 4 remaining unopened ballots are determinative. By Order dated October 12, 2006, the Regional Director transferred the case back to the Board for further consideration of the remaining determinative challenged ballots. On February 27, 2009, the NLRB ordered that all four ballots be opened and counted. If it is ultimately determined that the UMWA was validly elected, approximately 305 employees will be represented by the UMWA. In the event the Rockspring mining facility becomes unionized, we will bargain in good faith towards an acceptable collective bargaining agreement. If we are unable to do so, there could be strikes or other work stoppages detrimental to the normal operation of the Rockspring mining facility.

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

Efficient coal mining using modern techniques and equipment requires skilled laborers, preferably with at least a year of experience and proficiency in multiple mining tasks. In the event the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our coal.

Our ability to operate our company effectively could be impaired if we lose key personnel.

We manage our business with a number of key personnel. The loss of certain of these key individuals could have a material adverse effect on us. In addition, as our business develops and expands, we believe that our future success will depend greatly on our continued ability to retain and attract highly skilled and qualified personnel. Key personnel may not continue to be employed by us or we may not be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have a material adverse effect on us.

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

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

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

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. The current volatile economic environment and tight credit market conditions increase collection risks, particularly from industrial companies and non-regulated electricity generators. Our customer base is changing with deregulation as utilities sell their power plants to their non-regulated affiliates or third parties. These new power plant owners may have credit ratings that are below investment grade. If there is deterioration of the creditworthiness of electric power generator customers or trading counterparties, our business could be adversely affected. In addition, competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk we bear on payment default.

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

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

Provisions in our certificate of incorporation and bylaws may discourage a takeover attempt even if doing so might be beneficial to our shareholders.

Provisions contained in our certificate of incorporation and bylaws could make it more difficult for a third party to acquire us. Provisions of our certificate of incorporation and bylaws impose various procedural and other requirements, which could make it more difficult for shareholders to effect certain corporate actions. For example, our certificate of incorporation authorizes our board of directors to determine the rights, preferences, privileges and restrictions of unissued series of preferred stock, without any vote or action by our shareholders. Thus, our board of directors can authorize and issue shares of preferred stock with voting or conversion rights that could adversely affect the voting or other rights of holders of our common stock. These rights may have the effect of delaying or deterring a change of control of our company. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our common stock. The current global financial crisis may have significant effects on our customers and suppliers that could result in material adverse effects on our business, operating results, and stock price.

The current financial crisis and deteriorating economic conditions may have material adverse impacts on our business and financial condition that we currently cannot predict.

As widely reported, economic conditions in the United States and globally have been deteriorating. Financial markets in the United States, Europe and Asia have been experiencing a period of unprecedented turmoil and upheaval characterized by extreme volatility and declines in security prices, severely diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States federal government and other governments. Unemployment has risen while business and consumer confidence have declined, and there are fears of a prolonged recession. Demand for our products may drop and we may not be able to sell all the product we are capable of producing. This can impact our cost structure, revenues and opportunities for future growth. Although we cannot predict the impacts of the deteriorating economic conditions on us, our customers and our suppliers, these conditions could materially adversely affect our business and financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

We received a comment letter from the Securities Exchange Commission Staff (the "Staff") dated July 31, 2008 regarding our Form 10-K for the fiscal year ended December 31, 2007 that was filed February 29, 2008; our Form 10-Q for the quarter ended March 31, 2008 that was Filed May 9, 2008 and our Proxy Statement on Schedule 14A that was filed April 8, 2008. The comments generally related to subject matter addressed in the Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-Q and Form 10-K and subject matter addressed in our Compensation Discussion and Analysis in our Proxy Statement. We have exchanged correspondence with the Staff several times. With respect to our Form 10-Q filing we addressed the Staff comments in our Form 10-Q for the Quarter ended September 30, 2008 that was filed November 7, 2008. We have addressed the Staff's comments regarding our Form 10-K for the fiscal year ended December 31, 2007 in this filing. Regarding our Proxy Statement there remains one open comment that relates to the disclosure of the metrics for the individual performance targets for each named executive officer.

ITEM 2. PROPERTIES.

Coal Reserves

Periodically, we retain outside experts to independently verify our coal reserves. The most recent review was completed during the first quarter of 2004 and covered all of our reserves. The results verified our reserve estimates, with minor adjustments, and included an in-depth review of our procedures and controls. In 2006 and 2008 we retained outside experts to independently verify additional economically viable reserves. "As received" means measuring coal in its natural state and not after it is dried in a laboratory setting. We have recalculated all reserves on an "as received" basis. Our reserves were approximately 1.7 billion tons as of December 31, 2008.

Of the 1.7 billion tons, approximately 1.1 billion tons are assigned reserves that we expect to be mined at operations in the future. Approximately 0.6 billion tons are unassigned reserves that we are holding for future development. All of our reserves in Wyoming and Illinois are assigned. We have unassigned reserves in Pennsylvania and West Virginia of 0.5 billion tons and 0.1 billion tons, respectively.

Over 50% of our reserves are classified as high Btu coal (coal delivered with an average heat value of 12,500 Btu per pound or greater) and are located in Pennsylvania and West Virginia. Approximately 46% of our reserves are classified as compliance coal which meets the 1.2 lb SO_2 /mmBtu standard of Phase II of the Clean Air Act. Our compliance reserves are located in Wyoming and West Virginia.

The table below summarizes the locations, coal reserves in millions of tons and primary ownership of the coal reserves. Tonnage is on an as-received wet basis and the quality figures represent an approximate reserve average.

Operating Segments	Proven and Probable Reserves(1)	Assigned Reserves	Unassigned Reserves	Average Btu/lb	Average Sulfur Content (lbs SO_2/mmBtu)	Ownership
			(Tons in millions)			
Powder River Basin	760.3	760.3	-	8,400	0.8	Primarily Leased
Northern Appalachia	730.5	243.3	487.2	12,934	3.6	Primarily Owned
Central Appalachia	232.0	87.6	144.4	12,629	1.3	Primarily Leased
Illinois Basin	26.1	26.1	-	11,069	3.0	Primarily Leased
Total	1,748.9	1,117.3	631.6			

(1) Proven and probable coal reserves are classified as follows:

Proven reserves—Reserves for which: (i) 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 (ii) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

Probable reserves—Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

We believe that we have sufficient reserves to replace capacity from depleting mines for the foreseeable future and that our current reserves are one of our strengths. We believe that the current level of production at our major mines is sustainable for the foreseeable future.

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

Our mines in Wyoming are subject to federal coal leases that are administered by the U.S. Department of Interior under the Federal Coal Leasing Amendment Act of 1976. Each lease requires diligent development of the lease within ten years of the lease award with a required coal extraction of 1.0% of the reserves within that 10-year period. At the end of the 10-year development period, the mines are required to maintain continuous operations, as defined in the applicable leasing regulations. All of our federal leases are in full compliance with these regulations. We pay to the federal government an annual rent of $3.00 per acre and production royalties of 12.5% of gross proceeds on surface mined coal. Effective October 1, 2008, the Federal Government remits 48% of royalties, rentals and any lease bonus payments to Wyoming.

Certain of our mines in Pennsylvania, West Virginia and Illinois are subject to private coal leases. Private coal leases normally have a stated term and usually give us the right to renew the lease for a stated period or to maintain the lease in force until the exhaustion of mineable and saleable coal contained on the relevant site. These private leases provide for royalties to be paid to the lessor either as a fixed amount per ton or as a percentage of the sales price. Many leases also require payment of a lease rental or minimum royalty, payable either at the time of execution of the lease or in periodic installments. The terms of our private leases are normally extended by active production on or near the end of the lease term. Leases containing undeveloped reserves may expire or these leases may be renewed periodically.

Consistent with industry practice, we conduct only limited investigation of title to our coal properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased properties are not completely verified until we prepare to mine those reserves.

ITEM 3. LEGAL PROCEEDINGS.

From time to time, we are involved in legal proceedings arising in the ordinary course of business. We believe we have recorded adequate accruals for these liabilities and that there is no individual case or group of related cases pending that is likely to have a material adverse effect on our financial condition, results of operations or cash flows.

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

No matters were submitted to a vote of security holders during the fourth quarter of the year ended December 31, 2008.

PART II

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

The Company's common stock trades on the New York Stock Exchange under the symbol "FCL".

The following table sets forth, for the periods indicated, the range of high and low prices obtained from the New York Stock Exchange for the Company's Common Stock.

FISCAL PERIOD ENDED	HIGH PRICE	LOW PRICE
MARCH 31, 2007	$35.64	$29.77
JUNE 30, 2007	$45.28	$33.20
SEPTEMBER 30, 2007	$42.44	$30.87
DECEMBER 31, 2007	$53.00	$37.42
MARCH 31, 2008	$60.43	$41.63
JUNE 30, 2008	$89.69	$48.40
SEPTEMBER 30, 2008	$89.04	$30.34
DECEMBER 31, 2008	$34.90	$ 8.53

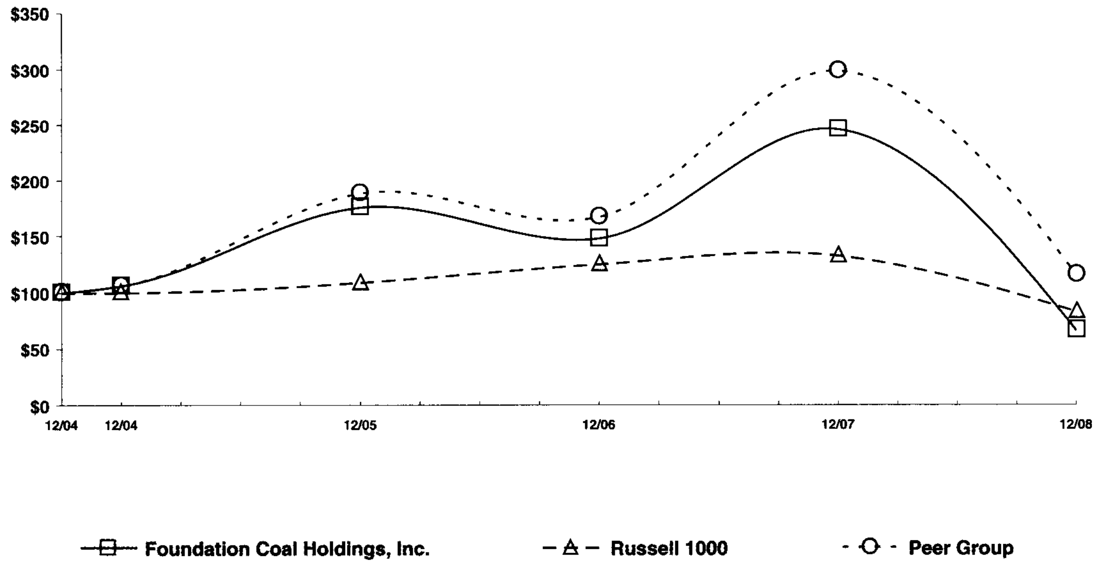
As of February 20, 2009, there were approximately 73 holders of record of the Common Stock and approximately 4,736 stockholders whose shares were held for them in street name or nominee accounts.

Stock Performance Graph

The following chart, produced by Research Data Group, depicts Foundation's performance for the period beginning on December 9, 2004 and ending December 31, 2008, as measured by total stockholder return on the common stock compared with the total return of the Russell 1000 Index and a custom composite index. The Peer Group custom composite index includes Peabody Energy Corporation, Arch Coal, Inc., Massey Energy Company, Consol Energy, Inc. and Alpha Natural Resources, Inc.

COMPARISON OF 49 MONTH CUMULATIVE TOTAL RETURN*

Among Foundation Coal Holdings, Inc., The Russell 1000 Index
And A Peer Group



* $100 invested on 12/9/04 in stock or index-inducing reinvestment of dividends.

Fiscal year ending December 31:

	Cumulative Total Performance*					
	12/9/2004	2004	2005	2006	2007	2008
Foundation Coal Holdings, Inc.	100	106.02	175.72	147.71	245.39	65.94
Russell 1000	100	100.00	108.63	125.43	132.67	82.79
Peer Group	100	105.94	188.25	167.19	298.06	115.63

* Reflects value of $100 invested on December 9, 2004, assumes dividends were reinvested and the investment was held through December 31, 2008.

Equity Compensation Plan Information

This table provides information about our common stock subject to equity compensation plans as of December 31, 2008.

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans
Approved By Stockholders*	1,031,869	$ 7.89	2,113,763

* We have one active equity compensation plan, the 2004 Stock Incentive Plan, as amended and approved by stockholders on December 8, 2004 and further amended and approved by stockholders on May 22, 2008. In addition, 318,604 shares are issuable to holders of restricted stock performance units upon the achievement of certain performance and vesting criteria.

Dividend Policy

We paid quarterly dividends totaling $0.20 per share during the years ended December 31, 2008 and 2007. Most recently, our Board of Directors declared a quarterly dividend of $0.05 per share on the Company's common stock on February 26, 2009, payable on March 27, 2009, to stockholders of record on March 17, 2009. The Board will determine the amount of any future dividends from time to time based on (a) our results of operations and the amount of our surplus available to be distributed, (b) dividend availability and restrictions under our credit agreement and indenture, (c) the dividend rate being paid by comparable companies in the coal industry, (d) our liquidity needs and financial condition and (e) other factors that our board of directors may deem relevant. Foundation PA Coal Company, LLC's Senior Secured Credit Facility and indenture governing the 7.25% Senior Notes currently limit the amount that Foundation Coal Corporation, in the case of the indenture, and its direct parent, in the case of the Senior Secured Credit Facility, can pay as dividends to us. See PART II, ITEM 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" for more detail on such limits. Our Board may continue to declare quarterly dividends in future periods.

Recent Sales of Unregistered Securities

We did not issue any securities that were exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act") in 2008.

Issuer Purchase of Equity Securities

On July 18, 2006, the Company announced a share repurchase program that authorizes the Company to repurchase $100,000,000 of its common stock. On September 29, 2008, the Company announced an increase in the share repurchase program that authorizes the Company to repurchase an additional $100,000,000 of its common stock, from time to time, as determined by authorized officers of the Company, up to an aggregate amount of $200,000,000. The table below summarizes key information on the share repurchase program from its inception through December 31, 2008.

	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Program	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (000's omitted)[2]
January 1, 2008 through January 31, 2008	-	$ -	-	$ 52,849
February 1, 2008 through February 28, 2008	-	$ -	-	$ 52,849
March 1, 2008 through March 31, 2008	36,546	$ 52.64	-	$ 52,849
April 1, 2008 through April 30, 2008	346	$ 49.50	-	$ 52,849
May 1, 2008 through May 31, 2008	1,313	$ 64.84	-	$ 52,849
June 1, 2008 through June 30, 2008	528	$ 88.23	-	$ 52,849
July 1, 2008 through July 31, 2008	82,300	$ 60.72	82,300	$ 47,852
August 1, 2008 through August 31, 2008	167,218	$ 59.89	166,800	$ 37,861
September 1, 2008 through September 30, 2008	266,400	$ 37.53	266,400	$ 127,863
October 1, 2008 through October 31, 2008	515,163	$ 27.74	514,645	$ 113,587
November 1, 2008 through November 30, 2008	-	$ -	-	$ 113,587
December 1, 2008 through December 31, 2008	-	$ -	-	$ 113,587
Total	1,069,814	$ 38.67	1,030,145	$ 113,587

(1) Includes the repurchase of 39,669 common shares withheld from employees to satisfy the employees' minimum statutory tax withholding upon vesting of restricted stock units.

(2) Management cannot estimate the number of shares that will be repurchased because decisions to purchase are based on company outlook, business conditions and current investment opportunity.

ITEM 6. SELECTED FINANCIAL DATA.

Foundation Coal Holdings, Inc. does not have any independent external operations, assets or liabilities, other than through its operating subsidiaries. The selected consolidated financial data as of and for the twelve months ended December 31, 2008, 2007, 2006 and 2005 and as of and for the period from February 9, 2004 (date of formation) through December 31, 2004 have been derived from the audited consolidated financial statements of Foundation Coal Holdings, Inc. From its formation on February 9, 2004 and prior to the acquisition of RAG American Coal Holding, Inc. on July 30, 2004, Foundation Coal Holdings, Inc. did not have any assets, liabilities or results of operations. Therefore, the selected historical consolidated financial data for the period from January 1, 2004 through July 29, 2004 have been derived from the audited consolidated financial statements of RAG American Coal Holding, Inc., the predecessor to Foundation Coal Holdings, Inc., which have been audited by Ernst & Young LLP, an independent registered public accounting firm. In the opinion of management, such consolidated financial data reflects all adjustments, consisting only of normal and recurring adjustments, necessary for a fair presentation of the results for those periods. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year or any future period. The period from February 9, 2004 to December 31, 2004 reflects preliminary purchase price allocations in preparing the financial data which was finalized during the twelve months ended December 31, 2005.

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

"Successor"—Represents the consolidated financial position of Foundation Coal Holdings, Inc. and consolidated subsidiaries as of December 31, 2008, 2007, 2006, 2005 and 2004 and the consolidated results of operations and cash flows for the twelve months ended December 31, 2008, 2007, 2006, 2005 and for the period from February 9, 2004 (date of formation) through December 31, 2004. Foundation Coal Holdings, Inc. had no significant activities until the acquisition on July 30, 2004. Therefore, the results of operations and cash flows for the period from February 9, 2004 (date of formation) through December 31, 2004 reflect only the activity for the five month operating period ended December 31, 2004.

"Predecessor"—Represents the consolidated results of operations and cash flows of RAG American Coal Holding, Inc. for all periods prior to the acquisition of RAG American Coal Holding, Inc. on July 30, 2004.

You should read the following data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the financial information included elsewhere in this Annual Report on Form 10-K, including the consolidated financial statements and related notes thereto.

	Successor					Predecessor
	Twelve Months Ended December 31, 2008	**Twelve Months Ended December 31, 2007**	**Twelve Months Ended December 31, 2006**	**Twelve Months Ended December 31, 2005**	**For the Period From February 9, 2004 (date of formation) Through December 31, 2004**	**Seven Months Ended July 29, 2004**
			(In thousands)			
Statement of Operations Data:						
Revenues:						
Coal sales	$ 1,663,080	$ 1,452,702	$ 1,440,162	$ 1,292,411	$ 436,035	$ 544,882
Other revenue[1]	27,050	36,961	30,159	24,518	8,561	6,153
Total revenues	1,690,130	1,489,663	1,470,321	1,316,929	444,596	551,035
Costs and expenses:						
Cost of coal sales (excludes depreciation, depletion and amortization)	1,321,638	1,131,506	1,110,922	936,201	345,791	484,457
Selling, general and administrative expenses (excludes depreciation, depletion and amortization)	69,104	60,103	53,152	50,707	24,649	27,375
Accretion on asset retirement obligations	11,429	10,155	8,510	8,507	3,300	4,020
Depreciation, depletion and amortization	212,166	202,029	183,201	211,186	84,843	61,236
Amortization of coal supply agreements	1,368	(3,414)	(13,122)	(84,903)	(67,238)	8,837
Net change in fair value of derivative instruments	9,447	-	-	-	-	-
Employee and contract termination costs and other	-	14,656	-	-	-	-
Write-down of long-livedassets[2]	-	-	30,782	1,633	-	-
Income (loss) from operations	64,978	74,628	96,876	193,598	53,251	(34,890)
Other income (expense):						
Interest expense	(46,960)	(53,666)	(64,525)	(59,495)	(26,677)	(18,010)
Interest income	992	3,531	3,011	1,261	973	1,274
Other[3]	-	-	(112)	-	530	(90,789)
Income (loss) from continuing operations before income tax (expense) benefit and equity in losses of affiliates	19,010	24,493	35,250	135,364	28,077	(142,415)
Income tax (expense) benefit	(6,646)	8,114	(3,831)	(46,461)	(13,600)	51,824
Equity in losses of affiliates	(810)	-	-	-	-	-
Income (loss) from continuing operations	$ 11,554	$ 32,607	$ 31,419	$ 88,903	$ 14,477	$ (90,591)

	Successor					Predecessor
	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006	Twelve Months Ended December 31, 2005	For the Period From February 9, 2004 (date of formation) Through December 31, 2004	Seven Months Ended July 29, 2004
	(In thousands, except per share data)					
Earnings per share data:						
Income (loss) from continuing operations, basic	$ 0.26	$ 0.72	$ 0.69	$ 1.99	$ 0.60	$ (660.56)
Income (loss) from continuing operations, diluted	$ 0.25	$ 0.70	$ 0.67	$ 1.92	$ 0.58	$ (660.56)
Weighted-average shares-basic	45,073	45,157	45,397	44,626	24,187	137
Weighted-average shares-diluted	46,061	46,423	46,813	46,275	25,019	137
Dividends declared per share	$ 0.20	$ 0.20	$ 0.20	$ 0.18	$ 26.11	$ -
Balance Sheet Data (at period end):						
Cash and cash equivalents	$ 42,326	$ 50,071	$ 33,720	$ 22,432	$ 470,313	
Total assets	$ 1,968,108	$ 1,908,164	$ 1,949,580	$ 2,008,120	$ 2,545,230	
Total debt	$ 599,785	$ 599,785	$ 626,625	$ 635,000	$ 685,000	
Stockholders' equity	$ 224,361	$ 336,337	$ 297,813	$ 339,250	$ 256,763	
Statement of Cash Flows Data:						
Net cash provided by (used in)						
Continuing operations:						
Operating activities	$ 234,138	$ 240,963	$ 225,666	$ 184,205	$ 62,254	$ (8,044)
Investing activities	$ (200,517)	$ (165,477)	$ (199,868)	$ (130,438)	$ (934,932)	$ (50,646)
Financing activities	$ (41,366)	$ (59,135)	$ (14,510)	$ (501,648)	$ 1,342,991	$ (127,821)
Capital expenditures	$ (156,929)	$ (174,394)	$ (187,217)	$ (140,216)	$ (33,573)	$ (52,695)
Other Financial Data:						
EBITDA[(4)(5)(6)]	$ 277,702	$ 273,243	$ 266,843	$ 319,881	$ 71,386	$ (55,606)
Cumberland mine force majeure[(7)]	$ -	$ -	$ -	$ -	$ -	$ 31,090
Ratio of earnings to fixed charges[(8)]	1.4x	1.4x	1.5x	3.1x	2.0x	-

(1) Other revenues include gains on disposition of assets and other non-coal sales revenues. See Note 24 to the Consolidated Financial Statements included elsewhere in this Annual Report on Form 10-K.

(2) Write-down of long-lived assets in 2005 of $1.6 million as a result of a change in mine plan at the Northern Appalachia business unit. In 2006, $1.4 million and $29.4 million were written off related to deferred mining royalties at the Central Appalachia business unit and certain long-lived assets at the Wabash mine, respectively.

(3) In the Predecessor period in 2004, Other includes expenses resulting from loss on termination of hedge accounting for interest rate swaps of $48.9 million, an additional non-cash mark-to-market gain of $5.8 million related to the interest rate swaps recorded in the period February 29 to April 27, 2004, expenses of $26.0 million related to a non-cash charge arising from settlement of a guarantee claim with the South Carolina Public Service Authority by means of entering into a multi-year coal supply agreement at prices below the then prevailing market prices for new coal supply agreements of similar duration and $21.7 million of cash prepayment penalties in connection with prepayment of substantially all remaining long-term indebtedness of the Predecessor.

(4) EBITDA, a measure used by management to measure performance, is defined as income (loss) from continuing operations, plus interest expense, net of interest income, income tax (expense), depreciation, depletion and amortization, and amortization of coal supply agreements. Our management believes EBITDA is useful to investors because it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry. EBITDA is not a recognized term under GAAP and does not purport to be an alternative to net income as a measure of operating performance or to cash flows from operating activities as a measure of liquidity. Because not all companies use identical calculations, this presentation of EBITDA may not be comparable to other similarly titled measures of other companies.

Additionally, EBITDA is not intended to be a measure of cash flow available for management's discretionary use, as it does not reflect certain cash requirements such as interest payments, tax payments and debt service requirements. The amounts shown for EBITDA as presented herein differ from the amounts calculated under the definition of EBITDA used in our debt instruments. The definition of EBITDA used in our debt instruments is further adjusted for certain cash and non-cash charges and is used to determine compliance with financial covenants and our ability to engage in certain activities such as incurring additional debt and making certain payments. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Covenant Compliance".

EBITDA is calculated and reconciled to income (loss) from continuing operations in the table below.

	Successor					Predecessor
	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006	Twelve Months Ended December 31, 2005	For the Period From February 9, 2004 (date of formation) Through December 31, 2004	Seven Months Ended July 29, 2004
	(In thousands)					
Income (loss) from continuing operations	$ 11,554	$ 32,607	$ 31,419	$ 88,903	$ 14,477	$ (90,591)
Interest expense	46,960	53,666	64,525	59,495	26,677	18,010
Interest income	(992)	(3,531)	(3,011)	(1,261)	(973)	(1,274)
Income tax expense (benefit)	6,646	(8,114)	3,831	46,461	13,600	(51,824)
Depreciation, depletion and amortization	212,166	202,029	183,201	211,186	84,843	61,236
Amortization of coal supply agreements	1,368	(3,414)	(13,122)	(84,903)	(67,238)	8,837
EBITDA	$ 277,702	$ 273,243	$ 266,843	$ 319,881	$ 71,386	$ (55,606)

(5) Income (loss) from continuing operations and EBITDA, as defined above, were impacted by the following non-cash charges (income):

	Successor					Predecessor
	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006	Twelve Months Ended December 31, 2005	For the Period From February 9, 2004 (date of formation) Through December 31, 2004	Seven Months Ended July 29, 2004
	(In thousands)					
Interest rate swaps[a]	$ -	$ -	$ 112	$ -	$ (530)	$ 43,050
Early debt extinguishment costs	$ -	$ -	$ -	$ -	$ -	$ 21,724
Accretion on asset retirement obligations reclamation expense	$ 11,429	$ 10,155	$ 8,510	$ 8,507	$ 3,300	$ 4,020
Write-down of long-lived assets	$ -	$ -	$ 30,782	$ 1,633	$ -	$ -
Amortization included in employee benefits expenses[b]	$ -	$ -	$ -	$ -	$ -	$ 10,318
Profit in inventory[c]	$ -	$ -	$ -	$ -	$ 3,753	$ -
Overburden removal included in depreciation, depletion and amortization[d]	$ -	$ -	$ -	$ (22,624)	$ (15,300)	$ -
Stock-based compensation expense[e]	$ 13,617	$ 6,570	$ 3,046	$ 1,595	$ -	$ -
Net change in fair value of derivative instruments[f]	$ 9,447	$ -	$ -	$ -	$ -	$ -

[a] The amount for the Predecessor includes $48.9 million of expense resulting from early debt extinguishment and termination of hedge accounting for interest rate swaps, less $5.8 million mark-to-market adjustment. The amount for the Successor in 2004 includes the mark-to-market gain on interest rate swaps not yet designated as cash flow hedges prior to December 31, 2004. In 2006, the amount includes the mark-to-market loss for the period during which the swaps did not qualify for cash flow hedge accounting.

[b] Represents the portion of pension, other postretirement and black lung expense resulting from amortization of unrecognized actuarial losses, prior service costs and transition obligations.

[c] Represents incremental cost of sales recorded in the period arising from the preliminary estimate of profit added to inventory in purchase accounting.

[d] In purchase accounting, the fair value of partially and fully uncovered coal included consideration of the effort spent prior to the purchase date to remove overburden and get the coal to its partially or fully uncovered state. Therefore, the fair value assigned to partially and fully uncovered coal reserves was higher than that assigned to other coal reserves. Depletion of coal reserves, including the incremental fair value related to pre-Acquisition overburden removal efforts is included in *Depreciation, depletion and amortization.* Subsequent to the Acquisition date and prior to the implementation of Emerging Issues Task Force Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry* on January 1, 2006, the cost associated with removal of overburden to uncover coal reserves was deferred until the related coal is mined and charged to *Cost of coal sales* when the coal is sold. All partially and fully uncovered coal valued at the Acquisition date was sold by December 31, 2005. For the twelve months ended December 31, 2005 and for the period from February 9, 2004 (date of formation) through December 31, 2004, *Depreciation, depletion and amortization* included the value of overburden removal performed prior to the Acquisition date, which would have been included in *Cost of coal sales* if incurred subsequent to the Acquisition date.

[e] Represents compensation expense attributable to stock options and restricted stock units awarded to employees and restricted stock awarded to certain directors.

[f] Represents mark-to-market losses on certain derivative instruments, see Note 16 to the Consolidated Financial Statements included elsewhere in this Annual Report on Form 10-K.

(6) Income (loss) from continuing operations and EBITDA, as defined above, were also impacted by the following unusual (income) expense:

	Successor					Predecessor
	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006	Twelve Months Ended December 31, 2005	For the Period From February 9, 2004 (date of formation) Through December 31, 2004	Seven Months Ended July 29, 2004
			(In thousands)			
Litigation/arbitration/ contract settlements, net[a]	$ (400)	$ (6,285)	$ (1,010)	$ -	$ -	$ 28,900
Transactions bonus[b]	$ -	$ -	$ -	$ -	$ -	$ 1,826
Long-term incentive plan expense[c]	$ -	$ -	$ -	$ -	$ -	$ 2,428
(Gain) loss on asset sales and sale of affiliates	$ (1,565)	$ (5,185)	$ (876)	$ (666)	$ 405	$ (960)
Other[d]	$ (1,566)	$ (9,485)	$ (140)	$ -	$ 3,746	$ -

[a] Represents arbitration awards and litigation settlements, net of related legal and tax fees. Legal and tax fees associated with these settlements were $0.5 million in the period January 1, 2004 to July 29, 2004. In 2007, represents contract termination costs incurred related to the idling of the Wabash mine.

[b] Represents the cost of a one-time bonus awarded to certain employees in connection with the Acquisition.

[c] Represents the cost of a long-term incentive plan instituted by the Predecessor in 2001 that was terminated prior to closing as required by the change in control provisions in the plan agreement. We have implemented a management equity program that will not result in a cash cost to us.

[d] In 2004, amount represents a $1.8 million bonus paid to senior management related to the IPO and a $2.0 million sponsor monitoring fee recorded by the Successor. This latter item was terminated in connection with the IPO. In 2006, amount represents a loss of longwall shields at the Emerald mine due to geological conditions. In 2007, represents employee termination costs incurred related to the idling of the Wabash mine.

(7) Represents the estimated impact on EBITDA of the temporary idling of our Cumberland mine in the first half of 2004 as a result of a revised interpretation of mine ventilation laws by MSHA.

(8) For purposes of this computation, "earnings" consist of pre-tax income from continuing operations (excluding minority interest and equity in earnings of affiliates) plus fixed charges. "Fixed charges" consist of interest expense on all indebtedness plus amortization of deferred costs of financing and the interest component of lease rental expense. Earnings were insufficient to cover fixed charges by the deficiency of $142.4 million for the seven months ended July 29, 2004.

PART II

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

Overview

As of December 31, 2008, based on annual production volumes, we are the fourth largest coal producer in the United States, operating twelve individual coal mines. Our active mining operations are located in southwest Pennsylvania, southern West Virginia and the southern Powder River Basin region of Wyoming. Four of our operations are surface mines, two of our operations are underground mines using highly efficient longwall mining technology and the remaining six operations are underground mines that utilize continuous miners. In addition to mining coal, we also purchase coal from other producers for resale or for the purpose of blending it with our own production.

For the year ended December 31, 2008, we sold 70.9 million tons of coal, including 69.3 million tons that were produced and processed at our operations. For the comparable period in 2007, we sold 73.6 million tons of coal, including 71.9 million tons that were produced and processed at our operations. For the twelve months ended December 31, 2008 and 2007, we purchased and resold approximately 1.6 million and 1.7 million tons of coal, respectively. As of December 31, 2008, we had approximately 1.7 billion tons of proven and probable coal reserves

We are primarily a supplier of steam coal to U.S. utilities for use in generating electricity. We also sell steam coal to industrial plants. Steam coal sales accounted for approximately 98% and 97% of our coal sales volume for the twelve month periods ended December 31, 2008 and 2007, respectively, representing approximately 89% of our coal sales revenue for the twelve months ended December 31, 2008 and 2007. We sell metallurgical coal to steel producers where it is used to make coke for steel production. Metallurgical coal accounted for approximately 2% and 3% of our coal sales volume for the twelve month periods ended December 31, 2008 and 2007, respectively, representing approximately 11% of our coal sales revenue for the twelve month periods ended December 31, 2008 and 2007.

While the majority of our revenues are derived from the sale of coal, we also realize revenues from coal production royalties, fees to transload coal through our Rivereagle facility on the Big Sandy River and revenues from the sale of coalbed methane, natural gas and Dry Systems Technologies equipment, filters, and parts.

Results of Operations

Twelve Months Ended December 31, 2008 Compared to Twelve Months Ended December 31, 2007

Coal sales realization per ton sold represents revenue realized on each ton of coal sold. It is calculated by dividing coal sales revenues by tons sold.

Revenues

	Twelve Months Ended December 31,		Increase (Decrease)	
	2008	2007	Amount	Percent
	(Unaudited, in thousands, except per ton data)			
Coal sales	$ 1,663,080	$ 1,452,702	$ 210,378	14 %
Other revenue	27,050	36,961	(9,911)	(27)%
Total revenues	$ 1,690,130	$ 1,489,663	$ 200,467	13 %
Tons sold	70,857	73,595	(2,738)	(4)%
Coal sales realization per ton sold	$ 23.47	$ 19.74	$ 3.73	19 %

Coal sales revenues for the twelve months ended December 31, 2008 increased by $210.4 million, or 14% compared to coal sales revenues for the twelve months ended December 31, 2007. Coal sales realization per ton increased 19% period-over-period, while tons sold decreased by 4% period-over-period. Consolidated coal sales realization per ton for the twelve months ended December 31, 2008 reflected increased prices per ton sold in three of our operating segments, consisting of a 35% increase in Central Appalachia, an 11% increase in Northern Appalachia and an 11% increase in the Powder River Basin.

Coal sales revenues in Northern Appalachia for the twelve months ended December 31, 2008 increased by $122.4 million, or 23% compared to coal sales revenues for the twelve months ended December 31, 2007 primarily due to higher tons shipped and higher coal sales realization per ton. Coal sales volumes in Northern Appalachia increased by 1.4 million tons, or 11% period-over-period and coal sales realization per ton increased 11% period-over-period due to increased pricing per ton sold. Coal sales volumes at the Cumberland mine increased 0.1 million tons, or 2% compared to the prior year period while production was relatively flat period over period. Coal sales volumes at the Emerald mine increased 1.3 million tons, or 22% compared to the prior year period and production increased 0.7 million tons, or 12% compared to the prior year period due primarily to the introduction of a second longwall in February, 2008 and operating both longwalls during the entire fourth quarter of 2008. During the twelve months ended December 31, 2008, shipments at Emerald included approximately 0.8 million tons of purchased coal. During the twelve months ended December 31, 2007, coal sales volumes and production at Emerald and Cumberland were negatively impacted as a result of a nine day strike by the UMWA.

Coal sales revenues in Central Appalachia for the twelve months ended December 31, 2008 increased $45.8 million, or 10% compared to coal sales revenues for the twelve months ended December 31, 2007 primarily as a result of higher coal sales realization per ton, partially offset by lower coal sales volumes. Coal sales volumes and revenues were also negatively impacted by the absence of coal purchased and resold due to the expiration of the synfuel tax credit in December 2007. However, coal sales realization per ton increased 35% period-over-period as a result of increased pricing per ton sold. Coal sales volumes declined by 1.6 million tons, or 19% in the twelve months ended December 31, 2008 compared to the prior year period. Coal sales volumes in Central Appalachia decreased at the Laurel Creek and Pioneer mines due to lower production. In general, our production in Central Appalachia has been limited by difficult geologic conditions, increased regulatory activity and shortages of skilled miners at our underground mines, particularly Laurel Creek. In January, 2009, the Company announced the idling of the Laurel Creek mining complex due to certain business conditions.

Coal sales revenues in the Powder River Basin for the twelve months ended December 31, 2008 increased $28.3 million, or 6% compared to coal sales revenues for the twelve months ended December 31, 2007 as a result of higher coal sales realization per ton partially offset by lower coal sales volumes. Coal sales realization per ton increased 11% period-over-period as a result of increased pricing per ton sold. Coal sales volumes in the Powder River Basin decreased 2.4 million tons, or 5% period-over-period due to a combination of transportation interruptions caused by adverse weather conditions including extensive flooding in the Midwest, the Company's decision to limit production due to market conditions for Powder River Basin coal, and reduced shipments on certain coal supply agreements tied to customer requirements. An 18% period-over-period decrease in production and shipments at Eagle Butte was partially offset by a 8% increase in production and shipments at Belle Ayr.

Coal sales revenues from our coal trading group increased $25.9 million in the twelve months ended December 31, 2008 to $30.0 million compared to $4.1 million in the same period in the previous year as a result of increased coal sales activities that resulted in physical delivery.

Other revenues for the twelve months ended December 31, 2008 decreased by $9.9 million, or 27%, compared to the twelve months ended December 31, 2007. The decrease was due to: (a) lower other miscellaneous revenues ($10.5 million); (b) the absence of synfuel revenues due to the expiration of the synfuel tax credit in December, 2007 ($5.4 million); (c) decreased gains on asset sales ($3.6 million); (d) a refund from the Combined Benefit Fund in 2007 ($1.3 million); partially offset by (e) increased coalbed methane revenues ($4.6 million); (f) increased revenues from the sale of equipment, filters, and parts by Dry Systems Technologies ($4.0 million); and (g) increased royalty revenue ($2.3 million).

Costs and Expenses

	Twelve Months Ended December 31,		Increase (Decrease)	
	2008	2007	Amount	Percent
	(Unaudited, in thousands)			
Cost of coal sales (excludes depreciation, depletion and amortization)	$ 1,321,638	$1,131,506	$ 190,132	17 %
Selling, general and administrative expenses (excludes depreciation, depletion and amortization)	69,104	60,103	9,001	15 %
Accretion on asset retirement obligations	11,429	10,155	1,274	13 %
Depreciation, depletion and amortization	212,166	202,029	10,137	5 %
Amortization of coal supply agreements	1,368	(3,414)	4,782	140 %
Employee and contract termination costs and other	-	14,656	(14,656)	(100)%
Net change in fair value of derivative instruments	9,447	-	9,447	-
Total costs and expenses	$ 1,625,152	$1,415,035	$ 210,117	15 %

Cost of coal sales. Cost of coal sales increased $190.1 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, primarily due to: (a) higher repair, maintenance and operating supply costs including diesel fuel ($71.9 million); (b) increased purchased coal costs as a result of increased pricing on coal purchases ($36.0 million); (c) increases in labor and benefit costs as a result of both compensation increases and hiring of additional personnel ($41.6 million); (d) increases in royalties primarily due to mining a higher proportion of coal subject to federal royalty ($24.7 million); (e) increased miscellaneous other expenses ($13.4 million); (f) increases in outside services ($10.2 million); (g) increased tax-related expenses ($2.2 million) and (h) increased longwall move expenses ($4.2 million); partially offset by (i) decreased transportation and loading costs ($7.7 million) and (j) decreased inventory charges to expense related to an overall lower ratio of tons sold vs. tons produced ($6.4 million). Cost of coal sales per ton was $18.65 for the twelve months ended December 31, 2008 compared to $15.37 for the twelve months ended December 31, 2007.

Selling, general and administrative expenses. Selling, general and administrative expenses for the twelve months ended December 31, 2008 increased $9.0 million compared to the twelve months ended December 31, 2007. Period-over-period increases were due to: (a) higher expenses incurred for employee compensation and benefit related expenses ($7.7 million) which includes approximately $2.7 million in additional stock-based compensation related to modifying the vesting and performance conditions for certain stock-based awards; and (b) higher overhead expenses attributed mainly to an increase in industry association membership fees and miscellaneous services ($4.4 million); partially offset by (c) lower consulting fees and insurance expenses ($3.1 million).

Accretion on asset retirement obligations. Accretion on asset retirement obligations is a result of accounting for asset retirement obligations under Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). Accretion represents the increase in the asset retirement liability to reflect the change in the liability for the passage of time because the initial liability is recorded at present value. Higher accretion expense in 2008 was due to increased asset retirement obligation estimates for the comparable periods.

Depreciation, depletion and amortization. Depreciation, depletion and amortization includes depreciation of plant and equipment, cost depletion of amounts assigned to owned and leased mineral rights and amortization of mine development costs, internal use software and leasehold improvements. Depreciation, depletion and amortization expense increased $10.1 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, primarily due to higher depreciation and amortization partially offset by decreased cost depletion. Depreciation and amortization increased by $11.5 million in the twelve months ended December 31, 2008 compared to the prior year period mainly due to depreciation associated with capital additions to plant and equipment during the twelve months ended December 31, 2008. Cost depletion decreased by $1.4 million due to decreased production period-over-period.

Coal supply agreement amortization. Application of purchase accounting in 2004 resulted in the recognition of a significant liability for below market priced coal supply agreements as well as a significant asset for above market priced coal supply agreements, both in relation to market prices at the date of acquisition of mining assets by the Company in 2004. Coal supply agreement amortization increased $4.8 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007 primarily due to a decrease in the credit to amortization expense from below market liability contracts of $9.0 million, partially offset by a $4.2 million decrease in amortization expense from above market contracts. Amortization of the liability for below market priced coal supply agreements during the twelve months ended December 31, 2008 was $5.1 million of credit to expense compared to $14.1 million of credit to expense in the comparable period of the prior year. Amortization of the asset for above market priced coal supply agreements during the twelve months ended December 31, 2008 was $6.5 million of expense compared to $10.7 million of expense in the comparable period of the prior year. As shipments on coal supply agreements valued in purchase accounting are completed, the period-over-period impact of the amortization on both the asset and liability balances will continue to diminish until approximately 2010 when shipments associated with these coal supply agreements are estimated to be complete.

Employee and contract termination costs and other. In April 2007, Wabash announced the idling of the mine in southern Illinois. As a result, the Company recognized employee termination costs of $6.0 million and $1.3 million in accordance with the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* ("SFAS No. 146") and the provisions of SFAS No. 112, *Employers' Accounting for Postemployment Benefits* ("SFAS No. 112"), respectively, during the twelve months ended December 31, 2007. During the twelve months ended December 31, 2007, the Company also recognized $2.0 million of direct and incremental costs related to additional benefit claims for certain severed employees. Additionally, the Company recorded contract termination costs of $5.2 million associated with the idling of the mine. These costs are recorded as *Employee and contract termination costs and other* in the Consolidated Statements of Operations and Comprehensive (Loss) Income.

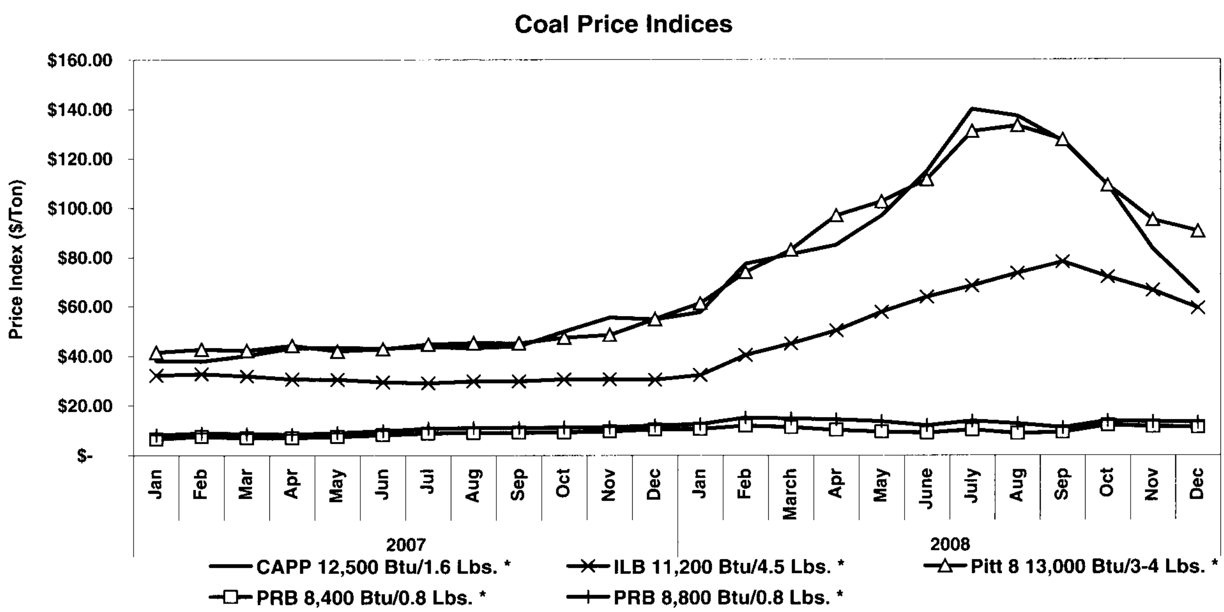
Net change in fair value of derivative instruments. The Company accounts for its derivative instruments in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activity* ("SFAS No. 133"), as amended. SFAS No. 133, as amended, requires all derivative instruments to be recognized as assets or liabilities and to be measured at fair value. For derivative instruments that have not been designated as cash flow hedges, changes in fair value are recorded in current period earnings or loss. For derivative instruments that have been designated as cash flow hedges, the effective portion of the changes in fair value are recorded in *Accumulated other comprehensive (loss) income* and any portion that is ineffective is recorded in current earnings or losses. Amounts recorded in *Accumulated other comprehensive (loss) income* are reclassified to earnings or losses in the period the underlying hedged transaction affects earnings or when the underlying hedged transaction is no longer probable of occurring.

The Company is subject to the risk of price volatility for certain of the materials and supplies used in production, such as diesel fuel and explosives. As a part of its risk management strategy, the Company enters into swap agreements with financial institutions to mitigate the risk of price volatility for both diesel fuel and explosives. The Company recorded unrealized losses of $4.1 million, $1.2 million and $0.3 million for the twelve months ended December 31, 2008 under the caption *Net change in fair value of derivative instruments* for certain diesel fuel related swaps that represented mark-to-market losses prior to the swaps being designated as qualifying cash flow hedges, mark-to-market losses for swaps that have not been designated as qualifying cash flow hedges and the ineffective portion of swaps that have been designated as qualifying cash flow hedges, respectively.

The Company evaluates each of its coal sales and coal purchase forward contracts under SFAS No. 133 to determine if they qualify for the normal purchase normal sale ("NPNS") exception prescribed by SFAS No. 133. The majority of our forward contracts do qualify for the NPNS exception based on management's intent and ability to physically deliver or take physical delivery of the coal. Contracts that do not qualify for the NPNS exception are treated as derivatives under SFAS No. 133 and are accounted for at fair value. Those contracts that qualify as derivatives have not been designated as cash flow hedges and accordingly, the Company includes the unrealized gains and losses in current period earnings or losses. The Company recorded net unrealized losses of $3.9 million related to contracts that qualify as derivatives in the Consolidated Statements of Operations and Comprehensive (Loss) Income for the twelve months ended December 31, 2008 under the caption *Net change in fair value of derivative instruments*.

Segment Analysis

Utilizing data published by Argus Media, the following graph sets forth representative steam coal prices in various U.S. markets summarized for the monthly periods from January 1, 2007 through December 31, 2008. The prices are not necessarily representative of the coal prices actually obtained by the Company. Changes in coal prices have an impact over time on the Company's average sales realization per ton and, ultimately, its consolidated financial results.



Source: Argus Media as published in Coal Daily/Coal Weekly

CAPP - Central Appalachia

ILB - Illinois Basin

Pitt 8 - Pittsburgh 8 Seam (Northern Appalachia)

PRB - Powder River Basin

* of sulfur dioxide (SO_2) per MMBtu

The market price of coal is influenced by many factors that vary by region. Such factors include, but are not limited to: (1) coal quality, which includes energy (heat content), sulfur, ash, volatile matter and moisture content; (2) transportation costs; (3) regional supply and demand; (4) available competitive fuel sources such as natural gas, nuclear or hydro; and (5) production costs, which vary by mine type, available technology and equipment utilization, productivity, geological conditions, and mine operating expenses.

The energy content or heat value of coal is a significant factor influencing coal prices as higher energy coal is more desirable to consumers and typically commands a higher price in the market. The heat value of coal is commonly measured in British thermal units or the amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit. Coal from the Eastern and Midwest regions of the United States tends to have a higher heat value than coal found in the Western United States.

Prices for our Powder River Basin coal, with its lower energy content, lower production cost and often greater distance to travel to the consumer, typically sells at a lower price than Northern and Central Appalachian coal that has a higher energy content and is often located closer to the end user. Illinois Basin coal generally has lower energy content and higher sulfur than Northern and Central Appalachian coal, but it has higher energy content than Powder River Basin coal.

	Twelve Months Ended December 31,		Increase (Decrease)	
	2008	2007	Tons/$	Percent
	(Unaudited, in thousands, except coal sales realization per ton and cost of coal sales per ton)			
Powder River Basin				
Tons sold	49,197	51,617	(2,420)	(5)%
Coal sales realization per ton	$ 10.11	$ 9.08	$ 1.03	11 %
Total revenues	$ 500,618	$ 470,886	$ 29,732	6 %
Cost of coal sales per ton[(1)]	$ 8.23	$ 6.45	$ 1.78	28 %
Income from operations	$ 25,560	$ 75,376	$ (49,816)	(66)%
Northern Appalachia				
Tons sold	14,398	12,993	1,405	11 %
Coal sales realization per ton	$ 44.72	$ 40.14	$ 4.58	11 %
Total revenues	$ 650,373	$ 533,789	$ 116,584	22 %
Cost of coal sales per ton[(1)]	$ 31.80	$ 27.31	$ 4.49	16 %
Income from operations	$ 94,626	$ 91,694	$ 2,932	3 %
Central Appalachia				
Tons sold	6,913	8,484	(1,571)	(19)%
Coal sales realization per ton	$ 71.17	$ 52.60	$ 18.57	35 %
Total revenues	$ 496,589	$ 458,271	$ 38,318	8 %
Cost of coal sales per ton[(1)]	$ 58.53	$ 46.68	$ 11.85	25 %
Income (loss) from operations	$ 22,511	$ (2,982)	$ 25,493	855 %

(1) Excludes selling, general and administrative expense; depreciation, depletion and amortization; accretion expense; and changes in fair value of derivative instruments

Powder River Basin—Income from operations decreased $49.8 million period-over-period due to increased operating costs of $74.1 million and a $5.4 million mark-to-market loss on financial swaps related to diesel fuel, partially offset by increased revenues of $29.7 million. As explained in the revenue section above, the increased revenues resulted from a 11% increase in coal sales realization per ton, partially offset by a 5% decrease in coal sales volumes. Coal sales volumes in the Powder River Basin decreased 2.4 million tons period-over-period due to a combination of transportation interruptions caused by adverse weather conditions including extensive flooding in the Midwest, the Company's decision to limit production due to market conditions for Powder River

Basin coal, and reduced shipments on certain coal supply agreements tied to customer requirements. An 18% period-over-period decrease in production and shipments at Eagle Butte was partially offset by a 8% increase in production and shipments at Belle Ayr. Operating costs increased $74.1 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, reflecting higher period-over-period cost of sales of $71.9 million, an increase in depreciation, depletion and amortization costs of $1.3 million and an increase in other miscellaneous expenses of $0.9 million.

The $71.9 million increase in cost of sales referred to above resulted from an increase in cash production costs ($71.8 million) and increased other expenses ($0.1 million). The $71.8 million period-over-period increase in cash production costs were primarily in the following areas: (a) supply and service costs primarily consisting of operating supply costs, repair and maintenance expenses, rent, explosives, diesel fuel and outside services ($41.7 million); (b) increased royalty costs mainly due to mining a higher amount of coal that is subject to federal royalties ($19.8 million); (c) labor and employee benefits ($8.4 million); and (d) increased miscellaneous expenses ($1.9 million). Cost of coal sales per ton increased 28% period-over-period.

Higher total depreciation, depletion and amortization costs of $1.3 million related primarily to a period-over-period $2.9 million increase in depreciation as a result of capital expenditures during the prior twelve months and increased depreciation related to the completion of an overland conveyor belt that was placed into service during the third quarter of 2007; partially offset by decreased depletion expense related to lower production period-over-period at the Eagle Butte mine ($0.7 million) and a decrease in expense associated with the amortization of coal supply agreements as shipments on a number of coal supply agreements valued in purchase accounting were completed ($0.9 million).

Northern Appalachia—Income from operations increased by $2.9 million period-over-period due to increased revenues of $116.6 million, partially offset by increased operating costs of $113.7 million. As explained in the revenue section above, the increase in revenues resulted from a 11% period-over-period increase in tons sold and a 11% increase in coal sales realization per ton. Coal sales volumes at the Cumberland mine increased 0.1 million tons, or 2% compared to the prior year period and production was relatively flat compared to the prior year period. Coal sales volumes at the Emerald mine increased 1.3 million tons, or 22% compared to the prior year period and production increased 0.7 million tons, or 12% compared to the prior year period due primarily to the introduction of a second longwall in February, 2008 and operating both longwalls during the entire fourth quarter of 2008. During the twelve months ended December 31, 2008, shipments at Emerald included approximately 0.8 million tons of purchased coal. During the twelve months ended December 31, 2007, coal sales volumes and production at Emerald and Cumberland were negatively impacted as a result of a nine day strike by the UMWA as well as geologic conditions that reduced production levels.

Operating costs increased $113.7 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, reflecting higher period-over-period cost of sales of $103.1 million; increases in depreciation, depletion and amortization costs of $10.5 million; and increased other expenses of $0.1 million.

The $103.1 million period-over-period increase in cost of sales referred to above was the result of increased cash production costs ($62.6 million); purchased coal expense for which there was no expense in the comparable period of 2007 ($45.6 million); increased miscellaneous other costs ($0.7 million); partially offset by decreased inventory charges to expense related to a lower ratio of tons sold vs. tons produced in the twelve months ended December 31, 2008 compared to the prior year period ($5.8 million). The $62.6 million increase in cash production costs were primarily incurred in the following areas: (a) higher labor and employee benefit costs, due to a higher number of employees and period-over-period wage and benefit increases, due primarily to the UMWA wage agreement signed in the second quarter of 2007 ($28.5 million); (b) higher supply and service costs primarily consisting of operating supply costs from increased prices for and usage of roof bolts and miner bits, increased water handling requirements, repairs and maintenance costs due to the timing of rebuilding longwall and other mining equipment and outside services ($28.7 million); (c) higher longwall move expenses ($4.2 million); and (d) increased miscellaneous expenses ($1.2 million). Cost of coal sales per ton increased by 16% period-over-period.

Higher total depreciation, depletion and amortization costs of $10.5 million related primarily to: (a) increased depreciation primarily related to longwall shields, face conveyors, other mining equipment and coalbed methane development costs ($9.9 million); (b) increased depletion expense ($1.4 million) due to increased production at the Emerald mine; partially offset by (c) a period-over-period decrease in expense associated with the amortization of coal supply agreements as shipments on a number of coal supply agreements valued in purchase accounting were completed ($0.8 million).

Central Appalachia—Income (loss) from operations increased by $25.5 million period-over-period due to increased revenues of $38.3 million that were partially offset by increased operating costs of $12.7 million and increased miscellaneous other expenses of $0.1 million. As explained in the revenue section above, the increase in revenues resulted from a 35% increase in coal sales realization per ton, partially offset by a 19% decrease in tons sold. Coal sales volumes in Central Appalachia decreased at the Laurel Creek and Pioneer mines due to lower production. In general, our production in Central Appalachia has been limited by difficult geologic conditions, increased regulatory activity and shortages of skilled miners at our underground mines, particularly Laurel Creek. In January, 2009, the Company announced the idling of the Laurel Creek mining complex due to certain business conditions. Coal sales volumes and revenues were also negatively impacted by the absence of coal purchased and resold due to the expiration of the synfuel tax credit in December 2007.

Operating costs increased $12.7 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, reflecting higher period-over-period cost of sales of $8.7 million; increases in depreciation, depletion and amortization costs of $3.6 million; and increased other expenses of $0.4 million.

The $8.7 million period-over-period increase in cost of sales referred to above was the result of increased cash production costs ($43.1 million); partially offset by decreased purchased coal expense ($32.8 million); decreased other costs ($1.1 million); and decreased inventory charges to expense related to a lower ratio of tons sold vs. tons produced in the twelve months ended December 31, 2008 compared to the prior year period ($0.5 million). The $43.1 million increase in cash production costs were primarily incurred in the following areas: (a) operating, supply and service costs primarily consisting of repairs and maintenance costs, operating supplies, utilities, explosives, transportation and loading, diesel fuel and outside services ($19.7 million); (b) labor and employee benefits ($13.1 million); (c) royalty expenses ($5.0 million); (d) tax-related expenses ($3.1 million); and (e) miscellaneous other expenses ($2.2 million). Cost of coal sales per ton increased by 25% period-over-period.

The $3.6 million increase in depreciation, depletion and amortization consisted of a reduced credit to expense for amortization of coal supply agreements of $5.8 million as shipments on a number of below market coal supply agreements valued as liabilities in purchase accounting were completed; partially offset by lower depletion expense of $2.1 million related to decreased production period-over-period at the Pioneer and Laurel creek mines and decreased depreciation of $0.1 million.

Other—Includes the Company's Illinois Basin operation, including the idled Wabash mine, which ceased operations in the second quarter of 2007; expenses associated with closed mines; Dry Systems Technologies; coal trading operations; selling, general and administrative expenses not charged out to the Powder River Basin, Northern Appalachia or Central Appalachia mines and intercompany eliminations. During the twelve months ended December 31, 2008, the Other segment reported a loss from operations of $77.7 million compared to a loss from operations of $89.5 million in the twelve months ended December 31, 2007. The decreased period-over-period loss from operations of $11.8 million in 2008 was primarily due to the absence of employee termination costs and other operating costs related to the idled Wabash mine, and increased revenues from our coal trading operations and Dry Systems Technologies; partially offset by a $3.9 million mark-to-market unrealized loss recorded for certain contracts executed by our coal trading operations that are being accounted for as derivatives and increased selling, general and administrative expenses.

Interest Expense, Net

	Twelve Months Ended December 31,		Increase (Decrease)	
	2008	2007	Amount	Percent
	(Unaudited, in thousands)			
Interest expense-debt related	$ (38,168)	$ (43,588)	$ (5,420)	(12)%
Interest expense-amortization of deferred financing costs	(1,834)	(2,090)	(256)	(12)%
Interest expense-surety bond and letter of credit fees	(6,489)	(5,979)	510	9 %
Interest expense-other	(469)	(2,009)	(1,540)	(77)%
Total interest expense	(46,960)	(53,666)	(6,706)	(12)%
Interest income	992	3,531	(2,539)	(72)%
Interest expense, net	$ (45,968)	$ (50,135)	$ (4,167)	(8)%

Interest expense, net for the twelve months ended December 31, 2008 decreased compared to the twelve months ended December 31, 2007 due to decreased interest expense related to the Senior Secured Credit Facility as a result of lower variable interest rates and repaying $25.1 million of principal in December, 2007; a decrease in other interest expense related to imputed interest for a deferred financing obligation for longwall shields that was paid in the fourth quarter of 2007; and decreased interest income due to lower interest rates realized on short-term investments and a lower average outstanding balance of cash held in short-term investments in the twelve months ended December 31, 2008 compared to the prior year period.

Income Tax (Expense) Benefit

	Twelve Months Ended December 31,		Decrease	
	2008	2007	Amount	Percent
	(Unaudited, in thousands)			
Income tax (expense) benefit	$ (6,646)	$ 8,114	$ (14,760)	(182)%

For the twelve months ended December 31, 2008, income tax expense of $6.6 million represents an effective rate of 35% on the pre-tax income of $19.0 million compared to an income tax benefit of $8.1 million, or a benefit of 33% on pre-tax income of $24.5 million for the twelve months ended December 31, 2007. The annual effective rate of 35% for 2008 increased from the 2007 effective benefit of 33% due to the recording of additional valuation allowances to reflect the impact of the federal alternative minimum tax ("AMT") system on the realizability of deferred tax assets, as well as additional valuation allowances due to federal and state net operating losses. Management continues to believe the Company will be an AMT taxpayer indefinitely.

Expected Coal Production

As of January 26, 2009, uncommitted and unpriced tonnage was 3%, 41%, and 71% of planned shipments in 2009, 2010, and 2011, respectively.

In 2009 through 2011, the Company expects coal shipments within the following ranges (millions of tons):

	2009	2010	2011
East	19.0-20.0	18.0-19.0	18.0-19.0
West	54.0-56.0	54.0-56.0	54.0-56.0
Total Consolidated	73.0-76.0	72.0-75.0	72.0-75.0

Based on its committed and priced planned shipments as of January 26, 2009, the Company expects its committed and priced tonnage from its Eastern mines, encompassing Northern Appalachia and Central Appalachia, to realize \$65.58, \$68.06 and \$78.82 per ton in 2009, 2010 and 2011, respectively. The Company also expects its committed and priced tonnage from the Powder River Basin to realize \$10.43, \$11.16 and \$12.13 per ton in 2009, 2010 and 2011, respectively. These expected per ton average realizations include forecasted sulfur dioxide and btu premiums based on contract terms, projected coal qualities and historical realized premiums.

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

Coal sales realization per ton sold represents the revenue realized on each ton of coal sold. It is calculated by dividing coal sales revenues by tons sold.

Revenues

	Twelve Months Ended December 31,		Increase (Decrease)	
	2007	2006	Amount	Percent
	(Unaudited, in thousands, except per ton data)			
Coal sales	$ 1,452,702	$ 1,440,162	$ 12,540	1%
Other revenue	36,961	30,159	6,802	23%
Total revenues	$ 1,489,663	$ 1,470,321	$ 19,342	1%
Tons sold	73,595	73,920	(325)	-
Coal sales realization per ton sold	$ 19.74	$ 19.48	$ 0.26	1%

Coal sales revenues for the twelve months ended December 31, 2007 increased by \$12.5 million, or 1% compared to coal sales revenues for the twelve months ended December 31, 2006. Tons sold decreased by less than 1% period over period and average coal sales realization per ton increased 1% period-over-period. The consolidated weighted-average sales realization per ton for the twelve months ended December 31, 2007 reflected a higher proportion of lower value Powder River Basin shipments compared to the same period in 2006.

Coal sales revenues in Northern Appalachia for the twelve months ended December 31, 2007 decreased by \$14.0 million, or 2.6% compared to coal sales revenues for the twelve months ended December 31, 2006 due primarily to a combination of lower coal sales volumes from lower tons shipped and lower coal quality premium/ penalty revenue, partially offset by higher base revenue. Coal sales revenue realization per ton in Northern Appalachia increased 3.4% period-over-period due to higher base revenue realization per ton, partially offset by lower coal quality premium/penalty revenue. Coal sales volumes in Northern Appalachia decreased by 0.8 million tons period-over-period as a result of decreased production and shipments from both mines. Tons sold at the Cumberland mine decreased 5.0% in the twelve months ended December 31, 2007 compared to the prior year period due to the nine day strike by the United Mine Workers of America ("UMWA") that began shortly after the wage agreement expired on April 1, 2007 and the scheduled longwall move that took place in the second quarter of 2007, inclusive of receiving an unanticipated regulatory ruling that delayed the restart of longwall production subsequent to the completion of the move. Emerald production and shipments were lower in 2007 compared to 2006 due to the nine day strike by the UMWA and geological challenges encountered in the third quarter which hindered mining activities and slowed production. Tons sold at the Emerald mine decreased 6.8% in the twelve months ended December 31, 2007 compared to the prior year period.

Coal sales revenues in Central Appalachia for the twelve months ended December 31, 2007 increased $1.3 million, or less than 1% compared to coal sales revenues for the twelve months ended December 31, 2006 primarily as a result of higher base revenues that were partially offset by lower coal quality premium/penalty revenues. Coal sales revenue realization per ton increased 4.9% period-over-period as a result of higher base revenue and lower coal quality premium/penalty revenue per ton. Coal sales volumes declined by 0.4 million tons, or 4.4% in the twelve months ended December 31, 2007 compared to the prior year period. Coal sales volumes in Central Appalachia decreased at all mining operations except for the Pax surface mine and from Laurel Creek's underground mines. Production in Central Appalachia was adversely impacted by reduced mining activities at the Rockspring mine in June 2007 to address regulatory issues related to new standards established for underground seals.

Coal sales revenues in the Powder River Basin for the twelve months ended December 31, 2007 increased $50.1 million, or 12.0% compared to coal sales revenues for the twelve months ended December 31, 2006. Coal sales revenue realization per ton sold increased 8.2% due to higher base revenue related to increased shipments under higher priced contracts in 2007, partially offset by lower coal quality premium/penalty revenue. Coal sales volumes in the Powder River Basin increased by 1.7 million tons, or 3.4% to a record twelve month shipment level of 51.6 million tons primarily due to an 8.2% increase in both production and shipments from the Belle Ayr mine, partially offset by lower period-over-period production and shipments at the Eagle Butte mine.

Coal sales revenues in the Illinois Basin for the twelve months ended December 31, 2007 decreased substantially compared to coal sales revenues for the twelve months ended December 31, 2006 due to the April 4, 2007 idling of the Wabash mine in southern Illinois.

Coal sales revenues from purchased coal activities by our trading group remained flat in the twelve months ended December 31, 2007 compared to the prior year period.

Other revenues for the twelve months ended December 31, 2007 increased by $6.8 million (22.6%) compared to the twelve months ended December 31, 2006. The increase was due to: (a) increased gains on the sale of assets ($4.3 million); (b) higher coalbed methane sales ($1.3 million); (c) increased miscellaneous other revenues ($3.6 million); (d) increased natural gas revenues ($3.0 million); partially offset by (e) lower synfuel fees ($1.1 million); (f) lower transloading and plant processing fees ($1.8 million); (g) decreased royalty revenues ($1.4 million); and (h) decreased revenues from the sale of equipment and filters by Dry Systems Technologies ($1.1 million).

Costs and Expenses

	Twelve Months Ended December 31,		Increase (Decrease)	
	2007	2006	Amount	Percent
	(Unaudited, in thousands)			
Cost of coal sales (excludes depreciation, depletion and amortization)	$ 1,131,506	$ 1,110,922	$ 20,584	2 %
Selling, general and administrative expenses (excludes depreciation, depletion and amortization)	60,103	53,152	6,951	13 %
Accretion on asset retirement obligations	10,155	8,510	1,645	19 %
Depreciation, depletion and amortization	202,029	183,201	18,828	10 %
Amortization of coal supply agreements	(3,414)	(13,122)	9,708	74 %
Employee and contract termination costs and other	14,656	-	14,656	-
Write-down of long-lived assets	-	30,782	(30,782)	(100)%
Total costs and expenses	$ 1,415,035	$ 1,373,445	$ 41,590	3 %

Cost of coal sales. Cost of coal sales increased $20.6 million for the twelve months ended December 31, 2007 compared to the twelve months ended December 31, 2006, primarily due to: (a) increases in labor and benefit costs as a result of both compensation increases and hiring of additional personnel ($20.8 million); (b) increases in royalties due to mining a higher proportion of coal subject to federal royalty ($1.7 million); (c) higher repair and maintenance and operating supply costs ($7.5 million); (d) increases in outside services ($3.9 million); (e) increased property, sales and production taxes ($7.6 million); (f) increased longwall move expenses ($2.1 million); and increased miscellaneous other expenses ($4.6 million) partially offset by (h) decreased transportation and loading costs ($4.3 million); decreased purchased coal costs as a result of lower purchased coal volumes ($17.6 million); and (i) a period-over-period decrease in inventory charges to expense related to an overall higher ratio of tons produced vs. tons sold in the twelve months ended December 31, 2007 compared to the prior year period ($5.7 million). Cost of coal sales per ton was $15.37 for the twelve months ended December 31, 2007 compared to $15.03 per ton for the twelve months ended December 31, 2006.

Selling, general and administrative expenses. Selling, general and administrative expenses for the twelve months ended December 31, 2007 increased $6.9 million compared to the twelve months ended December 31, 2006. Year-over-year increases were due to: (a) higher expenses incurred for employee compensation and benefit related expenses ($6.6 million); (b) higher consulting fees primarily related to implementation activities for our enterprise resource planning ("ERP") software that do not qualify as capital expenditures ($2.5 million); partially offset by (c) lower miscellaneous overhead expenses including legal and insurance expenses ($2.2 million).

Accretion on asset retirement obligations. Accretion on asset retirement obligations is a result of accounting for asset retirement obligations under SFAS No. 143. Accretion represents the increase in the asset retirement liability to reflect the change in the liability for the passage of time because the initial liability is recorded at present value. Higher accretion expense in 2007 was due to increased asset retirement obligation estimates.

Write-down of long-lived assets. In the fourth quarter of 2006, the company recognized a $30.8 million non-cash asset impairment charge which included $29.4 million to write down the carrying value of certain impaired assets at its Wabash mine and $1.4 million to write-off a non-recoverable prepaid royalty in Central Appalachia in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets* ("SFAS No. 144").

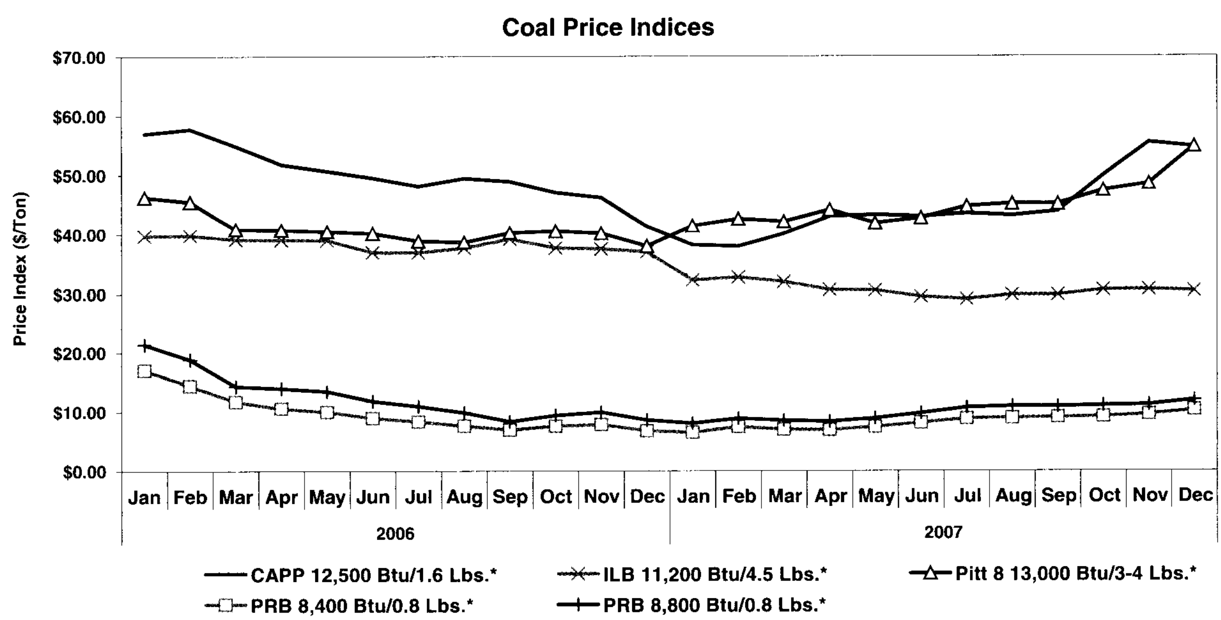
Depreciation, depletion and amortization. Depreciation, depletion and amortization includes depreciation of plant and equipment, cost depletion of amounts assigned to owned and leased mineral rights, amortization of mine development costs, internal use software and leasehold improvements. Depreciation, depletion and amortization expense increased $18.8 million for the twelve months ended December 31, 2007 compared to the twelve months ended December 31, 2006, primarily due to increased cost depletion and higher depreciation and amortization. Cost depletion increased by $1.7 million due to increased production period-over-period. Depreciation and amortization increased by $17.2 million in the twelve months of 2007 mainly due to capital additions to plant and equipment during the twelve months ended December 31, 2007 and the depreciation of the recently placed in service ERP software, which began depreciation at the beginning of the second quarter of 2007. Also contributing to higher depreciation expense in the twelve months ended December 31, 2007 was the completion of an overland conveyor belt that was placed into service in the third quarter of 2007 at the Powder River Basin.

Coal supply agreement amortization. Application of purchase accounting in 2004 resulted in the recognition of a significant liability for below market priced coal supply agreements as well as a significant asset for above market priced coal supply agreements, both in relation to market prices at the date of Acquisition of mining assets by the Company in 2004. Coal supply agreement amortization decreased $9.7 million for the twelve months ended December 31, 2007 compared to the twelve months ended December 31, 2006. Amortization of the liability for below market priced coal supply agreements during the twelve months ended December 31, 2007 was $14.1 million of credit to expense compared to $33.5 million of credit to expense in the comparable period of the prior year. Amortization of the asset for above market priced coal supply agreements during the twelve months ended December 31, 2007 was $10.7 million of expense compared to $20.4 million of expense in the comparable period of the prior year. As shipments on coal supply agreements valued in purchase accounting are completed, the period-over-period impact of the amortization on both the asset and liability balances will continue to diminish until approximately 2010 when shipments associated with these coal supply agreements are estimated to be complete.

Employee and contract termination costs and other. As discussed below in the section entitled "Wage Negotiations with the UMWA and Idling of the Company's Illinois Basin Mining Operation," Wabash announced the idling of the mine in southern Illinois on April 4, 2007. As a result of the Wabash idling, the Company recognized employee termination costs of $6.0 million and $1.3 million in accordance with the provisions of SFAS No. 146 and the provisions of SFAS No. 112, respectively, during the twelve months ended December 31, 2007. Termination costs resulting from one-time benefit arrangements include medical insurance continuance costs and severance to salaried employees. During the twelve months ended December 31, 2007, the Company also recognized $2.0 million of direct and incremental costs related to additional benefit claims for certain severed employees. Additionally, the Company recorded contract termination costs of $5.2 million associated with the idling of the mine. These costs are recorded as *Employee and contract termination costs and other* in the Consolidated Statements of Operations and Comprehensive (Loss) Income.

Segment Analysis

Utilizing data published by Argus Media, the following graph sets forth representative steam coal prices in various U.S. markets summarized for the monthly periods from January 1, 2006 through December 31, 2007. The prices are not necessarily representative of the coal prices actually obtained by the Company. Changes in coal prices have an impact over time on the Company's average sales realization per ton and, ultimately, its consolidated financial results.



Source: Argus Media as published in Coal Daily

CAPP - Central Appalachia

ILB - Illinois Basin

Pitt 8 - Pittsburgh 8 Seam (Northern Appalachia)

PRB - Powder River Basin

* of sulfur dioxide (SO_2) per MMBtu

The market price of coal is influenced by many factors that vary by region. Such factors include, but are not limited to: (1) coal quality, which includes energy (heat content), sulfur, ash, volatile matter and moisture content; (2) transportation costs; (3) regional supply and demand; (4) available competitive fuel sources such as natural gas, nuclear or hydro; and (5) production costs, which vary by mine type, available technology and equipment utilization, productivity, geological conditions, and mine operating expenses.

The energy content or heat value of coal is a significant factor influencing coal prices as higher energy coal is more desirable to consumers and typically commands a higher price in the market. The heat value of coal is commonly measured in British thermal units or the amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit. Coal from the Eastern and Midwest regions of the United States tends to have a higher heat value than coal found in the Western United States.

Prices for our Powder River Basin coal, with its lower energy content, lower production cost and often greater distance to travel to the consumer, typically sells at a lower price than Northern and Central Appalachian coal that has a higher energy content and is often located closer to the end user. Illinois Basin coal generally has lower energy content and higher sulfur than Northern and Central Appalachian coal, but it has higher energy content than Powder River Basin coal.

	Twelve Months Ended December 31,		Increase (Decrease)	
	2007	**2006**	**Tons/$**	**Percent**
	(Unaudited, in thousands, except coal sales realization per ton and cost of coal sales per ton)			
Powder River Basin				
Tons sold	51,617	49,918	1,699	3 %
Coal sales realization per ton	$ 9.08	$ 8.39	$ 0.69	8 %
Revenues	$ 470,886	$ 420,264	$ 50,622	12 %
Cost of coal sales per ton[1]	$ 6.45	$ 6.11	$ 0.34	6 %
Income from operations	$ 75,376	$ 46,986	$ 28,390	60 %
Northern Appalachia				
Tons sold	12,993	13,798	(805)	(6)%
Coal sales realization per ton	$ 40.14	$ 38.81	$ 1.33	3 %
Revenues	$ 533,789	$ 540,873	$ (7,084)	(1)%
Cost of coal sales per ton[1]	$ 27.31	$ 23.70	$ 3.61	15 %
Income from operations	$ 91,694	$ 143,858	$ (52,164)	(36)%
Central Appalachia				
Tons sold	8,484	8,870	(386)	(4)%
Coal sales realization per ton	$ 52.60	$ 50.16	$ 2.44	5 %
Revenues	$ 458,271	$ 455,507	$ 2,764	1 %
Cost of coal sales per ton[1]	$ 46.68	$ 44.92	$ 1.76	4 %
(Loss) income from operations	$ (2,982)	$ 10,584	$ (13,566)	(128)%

(1) Excludes selling, general and administrative expense; depreciation, depletion and amortization; accretion expense; and changes in fair value of derivative instruments

Powder River Basin— Income from operations increased $28.4 million period-over-period due to increased revenues of $50.6 million, partially offset by increased production costs of $22.2 million. As explained in the revenue section above, the increased revenues resulted from a 3% increase in tons sold and an 8% increase in average coal sales realization per ton. Assuming acceptable market conditions exist, we expect future increases in tons sold at the Belle Ayr mine primarily due to the expansion of its annual capacity. Production costs increased $22.2 million for the twelve months ended December 31, 2007 compared to the twelve months ended

December 31, 2006, reflecting higher period-over-period cost of sales of $28.3 million, an increase in other miscellaneous expenses of $1.4 million, partially offset by lower depreciation, depletion and amortization costs of $7.5 million.

The $28.3 million increase in cost of sales referred to above resulted from an increase in cash costs ($28.2 million) and increased miscellaneous other expenses ($0.1 million). The $28.2 million period-over-period increase in cash costs were primarily in the following areas: (a) excise taxes and coal production taxes, which respond to changes in coal sales revenues ($9.2 million); (b) supply and service costs primarily consisting of operating supply costs, explosives, diesel fuel and outside services ($12.4 million); (c) labor and employee benefits ($4.0 million); (d) rental expense ($1.7 million); (e) increased royalty costs due to mining a higher amount of coal that is subject to federal royalties ($1.0 million); partially offset by (f) miscellaneous expenses ($0.1 million). Cost of coal sales per ton increased 5.7% period-over-period.

Lower total depreciation, depletion and amortization costs of $7.5 million related primarily to a period-over-period $10.1 million reduction in charges for the amortization of coal supply agreements, as shipments on a number of coal supply agreements valued in purchase accounting were completed, partially offset by higher depreciation and depletion of $2.6 million as a result of higher capital expenditures during the prior twelve months and increased production period-over-period. Also contributing to the higher depreciation expense was the completion of an overland conveyor belt that was placed into service during the three months ended September 30, 2007.

Northern Appalachia—Income from operations decreased by $52.2 million period-over-period due to decreased revenues of $7.1 million and increased production costs of $45.1 million. As explained in the revenue section above, the decreased revenues resulted from a 6% period-over-period decrease in tons sold, partially offset by a 3% increase in average sales realization per ton. Coal sales volumes decreased primarily as a result of decreased production and shipments from both mines. Cumberland production and shipments were lower in 2007 due to the nine day strike by the UMWA that began shortly after the wage agreement expired on April 1, 2007 and the scheduled longwall move that took place in the second quarter of 2007 inclusive of receiving an unanticipated regulatory ruling that delayed the restart of longwall production subsequent to the completion of the move. Emerald production and shipments were lower in the 2007 period due to the nine day strike by the UMWA and geological challenges encountered during the third quarter of 2007 which hindered mining activities and slowed production. Tons sold at the Emerald mine decreased 7% in the twelve months ended December 31, 2007 compared to the prior year.

Total production costs increased $45.1 million for the twelve months ended December 31, 2007 compared to the twelve months ended December 31, 2006, reflecting higher year-over-year cost of sales of $27.8 million, higher depreciation, depletion and amortization costs of $16.2 million and higher miscellaneous other costs of $1.1 million.

The $27.8 million year-over-year increase in cost of sales referred to above was the result of increased cash costs $35.1 million, partially offset by decreased purchased coal expense ($3.4 million), lower miscellaneous other costs ($1.1 million) and decreased inventory charges to expense related to a higher ratio of tons produced vs. tons sold in the twelve months ended December 31, 2007 compared to the prior year ($2.8 million). The $35.1 million increase in cash costs were primarily incurred in the following areas: (a) higher labor and employee benefit costs, due to a higher number of employees and period-over-period wage and benefit increases, due primarily to the new UMWA wage agreement ($27.8 million); (b) higher supply and service costs primarily consisting of operating supply costs from increased usage of roof bolts, miner bits and water handling requirements, repairs and maintenance costs due to the timing of rebuilding longwall and other mining equipment and outside services ($10.1 million); (c) higher longwall move expenses ($2.1 million); partially offset by (d) lower transportation and loading costs ($3.9 million); and (e) lower miscellaneous expenses ($1.0 million). Cost of coal sales per ton increased by 15.2% period-over-period principally reflecting the effect of the UMWA strike and difficult geological conditions described above.

Higher total depreciation, depletion and amortization costs of $16.2 million related primarily to: (a) a period-over-period reduction in the credit associated with the amortization of coal supply agreements as shipments on a number of coal supply agreements valued in purchase accounting were completed ($9.9 million); (b) increased depreciation primarily related to a batch weigh system, longwall shields, face conveyors and other mining equipment ($6.7 million); and (c) lower depletion expense ($0.4 million) as a result of lower production by both mines during 2007.

Central Appalachia—Income from operations decreased by $13.6 million year-over-year due to increased revenues of $2.8 million that were offset by increased production costs of $16.4 million. As explained in the revenue section above, the increase in revenues resulted from a 5% increase in average sales realization per ton, partially offset by a 4% period-over-period decrease in tons sold. Total coal sales revenues for the twelve months ended December 31, 2007 remained flat compared to the twelve months ended December 31, 2006. Coal sales volumes in Central Appalachia decreased by 0.4 million tons (4%) period-over-period primarily from decreased shipments from all West Virginia mining operations except for the Pax surface mine and from Laurel Creek's underground mines. Production in Central Appalachia was adversely impacted by reduced mining activities at the Rockspring mine in June 2007 to address regulatory issues related to new standards established for underground seals.

The increase in production costs of $16.4 million for the twelve months ended December 31, 2007 compared to the twelve months ended December 31, 2006 consisted of higher depreciation, depletion and amortization ($19.3 million), partially offset by decreased cost of sales of ($2.4 million) and decreased miscellaneous other costs ($0.5 million). The $2.4 million decrease in cost of sales was a result of increased cash costs ($13.0 million), offset by a reduction in purchased coal expense ($12.2 million), decreased miscellaneous other expenses ($0.4 million) and a period-over-period decrease in inventory charges to expense related to a higher ratio of tons produced vs. tons sold in the twelve months ended December 31, 2007 compared to the prior year ($2.8 million).

The $13.0 million period-over-period increase in cash costs referred to above was primarily due to increases in the following areas: (a) labor and fringe benefits ($7.2 million); (b) supply and service costs primarily consisting of repairs and maintenance costs, operating supplies, utility, explosives, fuel costs and outside services ($4.7 million); (c) higher royalty expense ($1.2 million); (d) higher transportation and loading costs ($2.6 million); partially offset by (f) lower contract mining costs ($2.4 million); and (g) lower other miscellaneous costs ($0.3 million). Cost of coal sales per ton increased approximately 3.9% period-over-period.

The $19.3 million increase in depreciation, depletion and amortization consisted of higher depreciation of $7.5 million related to increased capital expenditures during the prior twelve months, higher reserve depletion of $1.6 million related to increased production period over period in mines that carry a higher depletion rate and a reduced credit to expense for amortization of coal supply agreements of $10.2 million as shipments on a number of coal supply agreements valued in purchase accounting were completed.

Other—Includes the Company's Illinois Basin operation, including the idled Wabash mine, which ceased operations in the second quarter of 2007; expenses associated with closed mines; Dry Systems Technologies; coal trading operations and selling, general and administrative expenses not charged out to the Powder River Basin, Northern Appalachia or Central Appalachia mines and intercompany eliminations. During the twelve months ended December 31, 2007, the Other segment reported a loss from operations of $89.5 million compared to a loss from operations of $104.6 million in the twelve months ended December 31, 2006. The decreased period-over-period loss from operations of $15.1 million was primarily due to the absence of long-lived asset impairment charges in 2007, partially offset by employee and contract termination costs incurred as a result of the idling of the Wabash mine and higher selling, general and administrative expenses.

Interest Expense, Net

	Twelve Months Ended December 31,		Increase (Decrease)	
	2007	2006	Amount	Percent
	(Unaudited, in thousands)			
Interest expense-debt related	$ (43,588)	$ (43,469)	$ 119	-
Interest expense-amortization of deferred financing costs	(2,090)	(11,653)	(9,563)	(82)%
Interest expense-surety bond and letter of credit fees	(5,979)	(6,749)	(770)	(11)%
Interest expense-other	(2,009)	(2,654)	(645)	(24)%
Total interest expense	(53,666)	(64,525)	(10,859)	(17)%
Interest income	3,531	3,011	520	17 %
Interest expense, net	$ (50,135)	$ (61,514)	$ (11,379)	(18)%

Interest expense, net for the twelve months ended December 31, 2007 was lower than the twelve months ended December 31, 2006 due primarily to decreased amortization of deferred financing costs and lower surety bond and letter of credit fees. Interest expense related to the amortization of deferred financing costs in the twelve months ended December 31, 2006 included a $9.2 million write-off of unamortized deferred financing costs recorded as a result of the Company's amendment to its debt agreement in July 2006. In 2007, the Company wrote off $0.2 million of unamortized deferred financing costs associated with the prepayment of $25.1 million of the term loan. The remaining reduction in the amortization of deferred financing cost period-over-period was caused by a lower deferred financing asset balance being amortized due to the aforementioned write-off in 2006. The reduction in surety bond and letter of credit fees was primarily attributable to fewer letters of credit outstanding.

Income Tax Benefit (Expense)

	Twelve Months Ended December 31,		Increase	
	2007	2006	Amount	Percent
	(Unaudited, in thousands)			
Income tax benefit (expense)	$ 8,114	$ (3,831)	$ 11,945	(312)%

For the twelve months ended December 31, 2007, income taxes were provided at an effective benefit rate of 33.1%. For the twelve months ended December 31, 2006 income taxes were provided at an effective rate of 10.9%. The most significant reason for the increase in income tax benefit for 2007 is due to the decrease in production and operating income at the Company's Emerald mine, which increased the impact of the permanent differences for excess depletion deductions on the effective tax rate. In addition, the Cumberland mine generated additional permanent differences for percentage depletion in 2007 compared to 2006.

Significant Property Transactions

In the first quarter of 2008, Foundation Wyoming Land Company an indirect wholly owned subsidiary of the Company, was the successful bidder on a new federal coal lease adjacent to the western boundary of the Eagle Butte mine located north of Gillette, Wyoming. The Company's lease bonus bid was $180,540, payable in five equal annual installments of $36,108. The Company made the first payment of $36,108 during the first quarter of 2008. The initial payment was capitalized as a component of *Owned and leased mineral rights, net* in the Consolidated Balance Sheets. Subsequent payments will be capitalized when paid. The lease became effective on May 1, 2008. This federal coal lease contains an estimated 224.0 million tons of proven and probable coal reserves.

In the third quarter of 2006, Pioneer Fuel Corporation, an indirect wholly owned subsidiary of the Company, purchased mining assets from Appalachian Fuels, LLC for $15.4 million. The purchased assets consisted of approximately 7.3 million tons of reserves, land and mining equipment. The acquired reserves are located adjacent to and have been integrated with the existing Pax surface operations and jointly managed. The purchase price was allocated to the assets and asset retirement obligation acquired/assumed based upon estimates of fair value. In a separate transaction, coal stockpiles containing an estimated 8,300 tons were also acquired from Appalachian Fuels, LLC for $0.2 million.

Liquidity and Capital Resources

Sources and Uses of Cash

Our primary sources of cash have been from sales of our coal production and, to a much lesser extent, purchased coal to customers, cash from sales of non-core assets and miscellaneous revenues.

Our primary uses of cash have been our cash production costs, capital expenditures, interest costs, cash payments for employee benefit obligations such as defined benefit pensions and retiree health care benefits, cash outlays related to post mining asset retirement obligations and support of working capital requirements such as coal inventories and trade accounts payable. Our ability to service debt and acquire new productive assets for use in our operations has been and will be dependent upon our ability to generate cash from our operations. We generally fund all of our capital expenditure requirements with cash generated from operations. Historically, we have engaged in minimal financing of assets such as through operating leases.

The following is a summary of cash provided by or used in each of the indicated categories of activities during the twelve months ended December 31, 2008 and 2007, respectively.

	Twelve Months Ended December 31,	
	2008	**2007**
	(Unaudited, in thousands)	
Cash provided by (used in):		
Operating activities	$ 234,138	$ 240,963
Investing activities (primarily capital expenditures)	(200,517)	(165,477)
Financing activities-borrowings	16,000	-
Financing activities-repayments	(16,000)	(26,784)
Financing activities-stock option exercise proceeds and excess tax benefit from stock-based awards	9,036	7,920
Financing activities-dividends on common stock	(9,025)	(9,027)
Financing activities-common stock repurchase	(39,263)	(35,262)
Financing activities-other	(2,114)	4,018
Change in cash and cash equivalents	$ (7,745)	$ 16,351

Cash provided by operating activities decreased $6.8 million for the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, primarily due to a $21.1 million decrease in net income and a $38.5 million decrease in cash flows from working capital changes, partially offset by a $52.8 million increase in non-cash add-backs to net income period-over-period. Working capital changes consist primarily of trade accounts receivable, inventory, prepaid expenses and other current and non-current assets, trade accounts payable, accrued expenses, other current and non-current liabilities.

Cash used in investing activities increased $35.0 million in the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, due primarily to: (a) a $36.1 million lease bonus-bid payment related to the successful bid on new federal coal lease located in the Powder River Basin; and (b) $10.3

million in purchases of equity-method investments; partially offset by (c) decreased capital expenditures, net of proceeds from disposals, for property and equipment of $11.4 million. Capital expenditures in the twelve months ended December 31, 2008 totaled $156.9 million which included $67.5 million for the following projects: (a) the acquisition and rebuild of longwall components at Emerald; (b) capital expenditures related to our coal gas recovery projects and land acquisitions and (c) expenditures for air and bleeder shafts. Capital expenditures in the twelve months ended December 31, 2007 totaled $174.4 million, including a total of $62.3 million of expenditures related to the following projects: (a) an overland coal conveyor at the Belle Ayr Mine in the Powder River Basin; (b) the acquisition and rebuild of longwall components and upgrades to the rail loading facility at Emerald; (c) capital expenditures related to our coal gas recovery projects; and (d) the acquisition and implementation of company wide ERP software.

Cash used in financing activities of $41.4 million during the twelve months ended December 31, 2008 consisted of (a) $39.3 million for the repurchase of common shares in accordance with the stock repurchase program initiated by the Company during the third quarter of 2006 and $2.1 million for the repurchase of common shares withheld from employees to satisfy employees' minimum statutory tax withholding upon vesting of restricted stock units; (b) payment of cash dividends of $9.0 million ($0.05 per share paid in March, June, September and December 2008); partially offset by (c) cash proceeds from the exercise of nonqualified stock options and excess tax benefits from stock-based awards ($9.0 million). Cash used in financing activities of $59.1 million during the twelve months ended December 31, 2007 consisted of: (a) $35.3 million related to the repurchase of common shares in accordance with the stock repurchase program initiated by the Company during the third quarter of 2006; (b) payment of quarterly cash dividends of $9.0 million ($0.05 per share paid in March, June, September and December 2007); (c) repayment of long-term debt ($26.8 million); and (d) cash proceeds related to the issuance of common stock for stock option exercises, excess tax benefit from stock-based awards and other financing cash proceeds ($11.9 million).

The following is a summary of cash provided by or used in each of the indicated categories of activities during the twelve months ended December 31, 2007 and 2006, respectively.

	Twelve Months Ended December 31,	
	2007	**2006**
	(Unaudited, in thousands)	
Cash provided by (used in):		
Operating activities	$ 240,963	$ 225,666
Investing activities (primarily capital expenditures)	(165,477)	(199,868)
Financing activities-repayments	(26,784)	(8,375)
Financing activities-stock option exercise proceeds and excess tax benefit from stock-based awards	7,920	17,041
Financing activities-proceeds from interest rate swap termination	-	2,259
Financing activities-dividends on common stock	(9,027)	(9,089)
Financing activities-deferred financing costs	-	(4,457)
Financing activities-common stock repurchase	(35,262)	(11,889)
Financing activities-other	4,018	-
Change in cash and cash equivalents	$ 16,351	$ 11,288

Cash provided by operating activities increased $15.3 million for the twelve months ended December 31, 2007 compared to the twelve months ended December 31, 2006, primarily due to a $17.5 million increase in cash flows from working capital changes and a $1.2 million increase in net income, partially offset by a $3.4 million decrease in non-cash add-backs to net income period-over-period. Working capital changes consist primarily of trade accounts receivable, inventory, prepaid expenses and other current and non-current assets, trade accounts payable, accrued expenses, other current and non-current liabilities.

Cash used in investing activities decreased $34.4 million in the twelve months ended December 31, 2007 compared to the twelve months ended December 31, 2006, primarily due to: (a) a $27.5 million decrease in capital expenditures and mine asset acquisitions; and (b) a $6.9 million increase in asset sales proceeds. Capital expenditures in the twelve months ended December 31, 2007 totaled $174.4 million which included $62.3 million for the following projects: (a) an overland coal conveyor at the Belle Ayr mine in the Powder River Basin; (b) the acquisition of longwall components and upgrades to the rail loading facility at Emerald; (c) capital expenditures related to our coal gas recovery projects; and (d) the acquisition and implementation of company wide ERP software. Capital expenditures in the twelve months ended December 31, 2006 totaled $187.2 million, including a total of $99.0 million of expenditures related to the following projects: (a) an overland coal conveyor at the Belle Ayr mine in the Powder River Basin; (b) equipment for and development of the Pax surface mine and related rail loading facility in Central Appalachia; (c) upgrades to the rail loading facility at Emerald; (d) construction of a new slope, overland coal conveyor and related coal handling facilities at the Wabash mine in Illinois; (e) progress payments toward the purchase of a second longwall at the Emerald mine; and (f) the acquisition and implementation of company wide ERP software.

Cash used in financing activities of $59.1 million during the twelve months ended December 31, 2007 consisted of (a) $35.3 million related to the repurchase of common shares in accordance with the stock repurchase program initiated by the Company during the third quarter of 2006; (b) payment of cash dividends of $9.0 million ($0.05 per share paid in March, June, September and December 2007); (c) repayment of long-term debt ($26.8 million); and (d) cash proceeds related to the issuance of common stock for stock option exercises, excess tax benefit from stock-based awards and other financing cash proceeds ($11.9 million). Cash used in financing activities during the twelve months ended December 31, 2006 consisted of (a) $7.6 million in cash proceeds from exercise of nonqualified stock options; (b) $9.5 million in excess income tax benefit from issuance of stock-based awards; and (c) $2.3 million in cash proceeds from the settlement of the interest rate swaps; offset by (d) cash dividends of $9.1 million ($0.05 per share paid in March, June, September and December 2006); (e) $11.9 million related to the repurchase of common shares in accordance with the stock repurchase program initiated by the Company during the third quarter; (f) $8.4 million for the repayment of long-term debt; and (g) $4.4 million for the payment of financing costs related to bank debt refinancing activities in the third quarter.

Liquidity and Long-Term Debt

Our primary source of liquidity will continue to be cash from sales of our coal production and to a much lesser extent, sales of purchased coal to customers. We have borrowing availability under our revolving credit facility, subject to certain conditions.

Based on our current levels of operations, we believe that remaining cash on hand, cash flow from operations and available borrowings under the revolving credit portion of our Senior Secured Credit Facility will enable us to meet our working capital, capital expenditure, debt service and other funding requirements for at least the next twelve months.

As of December 31, 2008, we have outstanding $599.8 million in aggregate indebtedness, with an additional $329.1 million of available borrowings under our revolving credit facility after giving effect to $170.9 million of letters of credit outstanding as of December 31, 2008. Our future liquidity requirements will be significant due to debt service requirements and projected capital expenditures. Our ability to service our debt (interest and principal), acquire new productive assets or businesses, develop new mines and expand or enhance existing operations is dependent upon our ability to continue to generate cash in excess of our anticipated uses of cash. We expect to service our debt, pay dividends and fund most of our capital expenditure requirements with cash generated from operations.

Our liquidity has historically been impacted by events initiated by the Company and will be impacted by future planned and possible unplanned events. Examples of known trends, planned and completed events which required liquidity include, but are not limited to: (1) the voluntarily prepayment during 2006 and 2007 of $33.5

million of the Company's outstanding principal balance on the term loan facility for which scheduled payments were due in periods from 2007 to 2009. The Company is required to resume quarterly principal payments of $8.4 million beginning September 2009; (2) paying quarterly dividends to stockholders and the expectation that our Board may continue to declare quarterly dividends in future periods; (3) we have historically increased our reserve position by obtaining mining rights to federal coal reserves adjoining our current operations in Wyoming through the Lease By Application ("LBA") process and plan to attempt to do so in the future; (4) the repurchase of common shares in accordance with our established program; and (5) capital expenditures made for the purpose of both sustaining and expanding operations.

Near-term, 2009 liquidity requirements will be impacted by planned capital expenditures which include: (1) the 2009 LBA bonus-bid payment of $36.1 million; (2) capital expenditures during calendar year 2009 of which $150.0 million to $180.0 million is to maintain production and replace mining equipment; (3) $40.0 million to $60.0 million is expected to be directed toward improvements in productivity and selective expansions of production; and (4) we expect to contribute approximately $30.0 million to our defined benefit retirement plans and to pay approximately $26.0 million of retiree health care benefits, gross of Medicare Part D subsidies, in calendar year 2009. In the foreseeable future, we expect to require similar levels of liquidity to fund LBA bonus-bid payments, capital expenditures, defined benefit plan obligations, other contractual commitments, operational and general working capital requirements.

The recent credit crisis has resulted in unprecedented redemption pressure on money market funds in general. With respect to our short-term investments classified on our Consolidated Balance Sheets in *Cash and cash equivalents*, the Company has not been affected, and our investments continue to meet the qualification of cash equivalents.

With respect to recent global economic events, there is an unprecedented uncertainty in the financial markets and this uncertainty brings potential liquidity risks to the Company. Such risks include additional declines in our stock value, less availability and higher costs of additional credit, potential counterparty defaults and further commercial bank failures. Although the majority of the financial institutions in our bank credit facility appear to be strong, there are no assurances of their continued existence as the banking industry continues to consolidate. However, we have no indication that any such transactions would impact our current credit facility. The credit worthiness of our customers is constantly monitored by the Company. We believe that our current group of customers are sound and represent no abnormal business risk.

We sponsor pension plans in the United States for salaried and non-union hourly employees. For these plans, the Pension Protection Act of 2006 ("Pension Act") requires a funding target of 100% of the present value of accrued benefits. The Pension Act includes a funding target phase-in provision that establishes a funding target of 92% in 2008, 94% in 2009, 96% in 2010 and 100% thereafter for defined benefit pension plans. Generally, any such plan with a funding ratio of less than 80% will be deemed at risk and will be subject to additional funding requirements under the Pension Act. The current volatile economic environment and the rapid deterioration in the equity markets since July 1, 2008 may have caused investment income and the value of investment assets held in our pension trust to decline and lose value. As a result, we may be required to increase the amount of cash contributions into the pension trust in order to comply with the funding requirements of the Pension Act. In 2008 we contributed $11.3 million to our pension plans. We currently expect to make contributions in 2009 of approximately $30.0 million to maintain at least an 80% funding ratio.

Bank Debt Refinancing

Our Senior Secured Credit Facility consists of a revolving credit facility and a term loan facility.

During 2006, the Company completed an $835.0 million amended and restated Senior Secured Credit Facility (the "facility") agreement consisting of a five-year $335.0 million Term Loan A and a five-year $500.0 million revolving credit facility. The credit facility, which matures on July 11, 2011, bears interest at an applicable margin, plus the lenders' base rate or LIBOR at the Company's option, and requires the Company to pay a commitment fee to the lenders for the unutilized portion of the commitment under the revolving credit facility based on a quarterly leverage ratio calculation. The revolving credit facility provides for up to $500.0 million of borrowings for base rate loans, LIBOR loans or letters of credit up to a maximum of the unutilized portion of the revolver. Costs capitalized in connection with the credit facility were $4.5 million and are being amortized over the term of the related indebtedness of five years, using the effective interest method. The Company wrote-off $9.2 million of unamortized deferred financing costs in the twelve months ended December 31, 2006, which is included in *Interest expense* in the Consolidated Statements of Operations and Comprehensive (Loss) Income, as a result of the replacement of the original Senior Secured Credit Facility. The credit facility replaces the previous Senior Secured Credit Facility and provides more favorable pricing and financial flexibility.

On December 31, 2007 the Company voluntarily prepaid $25.1 million, of the outstanding balance of the Term Loan due in 2008 and 2009, and wrote-off an additional $0.2 million of unamortized deferred financing costs in the twelve months ended December 31, 2007.

Borrowings under our credit facility bear interest at a floating rate plus an applicable margin. The highest applicable margin for borrowings under both the revolving credit facility and the Term Loan is 0.75% with respect to base rate borrowings and 1.75% with respect to LIBOR borrowings. Based on our leverage ratio as of December 31, 2008, the applicable margins on the revolving credit facility and the Term Loan were 1.25% and 1.25%, respectively.

In addition to paying interest on outstanding principal under the credit facility, we are required to pay a commitment fee to the lenders under the revolving credit facility in respect of the unutilized commitments, beginning at a rate equal to 0.375% per annum of the unused commitment. Based on our leverage ratio as of December 31, 2008, our rate was 0.25%. We also pay customary letter of credit fees.

The credit facility requires us to prepay outstanding term loans, subject to certain exceptions, in certain situations. Any mandatory prepayments would be applied to the remaining scheduled installments of the Term Loan on a pro rata basis. Optional prepayments would be applied to the Term Loan at our direction. If prepaid, there may be a charge for any breakage costs.

We are required to repay installments on the Term Loan in quarterly principal amounts of $8.4 million beginning September 2009 through March 2011, with the remaining balance of $242.9 million due on the July 11, 2011 maturity date.

Principal amounts outstanding under the revolving credit facility will be due and payable in full at maturity, five years from the date of the closing of the credit facility. As of December 31, 2008, there were no amounts outstanding under the revolving credit facility.

The credit facility contains a number of covenants that, among other things, restrict, subject to certain exceptions, the ability of certain of our subsidiaries, and the ability of each guarantor under the credit facility to incur additional indebtedness or issue preferred stock, repay other indebtedness (including the 7.25% Senior Notes), pay dividends and distributions or repurchase our capital stock, make investments, loans or advances, make certain acquisitions, engage in mergers or consolidations, enter into sale and leaseback transactions and enter into hedging agreements. Financial covenants include an interest coverage ratio test, a leverage ratio test and a limit on capital expenditures.

The indenture governing our outstanding 7.25% Senior Notes limits our ability and the ability of our restricted subsidiaries to incur additional indebtedness, pay dividends on or make other distributions or repurchase our capital stock, make certain investments, limit dividends or other payments by its restricted subsidiaries to us, and sell certain assets or merge with or into other companies. Our indenture permits the payment to us by Foundation Coal Corporation of $25.0 million, plus, for payment of dividends, an amount up to

5% per calendar year of the net proceeds received by Foundation Coal Corporation from the IPO. Foundation Coal Corporation will have the ability, subject to certain exceptions as set forth in the indenture, to incur additional indebtedness if it meets certain conditions, including having greater than a 2.0 to 1.0 fixed charge coverage ratio.

Financial Swaps

The Company is subject to the risk of price volatility for certain of the materials and supplies used in production, such as diesel fuel and explosives. As a part of its risk management strategy, the Company enters into swap agreements with financial institutions to mitigate the risk of price volatility for both diesel fuel and explosives. At December 31, 2008, liabilities related to the fair value of swaps that are expected to settle in the next twelve months were $23.7 million.

On September 30, 2004, the Company entered into pay-fixed, receive-variable interest rate swap agreements on a notional amount of $85.0 million that was designated as a qualifying cash flow hedge. In connection with the July 7, 2006 closing of the Company's Sr. Secured Credit Facility, the Company terminated the swap agreements. Subsequently, the Company monetized the $2.4 million derivative asset included in *Other noncurrent assets* in the Company's consolidated financial statements at June 30, 2006 and recognized a $0.1 million mark-to-market loss on the swaps. The $1.8 million unrealized gain from the change in the market value of the interest rate swaps recorded in *Accumulated other comprehensive (loss) income* was being recognized into income on a prorated basis over the remaining term of the original interest rate swap agreement through September 28, 2007. At December 31, 2006, the unamortized unrealized gain was $1.1 million, which was fully offset against *Interest expense* during the twelve months ended December 31, 2007.

Other

As a regular part of our business, we review opportunities for, and engage in discussions and negotiations concerning, the acquisition of coal mining assets, including LBA bids to procure federal coal, and acquisitions of, or combinations with, coal mining companies. When we believe that these opportunities are consistent with our growth plans and our acquisition criteria, we will make bids or proposals and/or enter into letters of intent and other similar agreements, which may be binding or nonbinding, that are customarily subject to a variety of conditions and usually permit us to terminate the discussions and any related agreements if, among other things, we are not satisfied with the results of our due diligence investigation. Any acquisition opportunities we pursue could materially affect our liquidity and capital resources and may require us to incur indebtedness, seek equity capital or both. There can be no assurance that such additional indebtedness and/or equity capital will be available on terms acceptable to us, if at all.

On February 20, 2008, an affiliate of the Company successfully bid on a new federal coal lease which contains an estimated 224.0 million tons of proven and probable coal reserves. The lease bonus bid was $180.5 million to be paid in five equal annual installments of $36.1 million. The first installment was paid during the three months ended March 31, 2008. The lease became effective on May 1, 2008.

On July 18, 2006, the Board of Directors authorized a stock repurchase program (the "Repurchase Program"), authorizing the Company to repurchase shares of its common stock. The Company may repurchase its common stock from time to time as determined by authorized officers of the Company. In September 2008 the Board of Directors authorized a $100.0 million increase to the Repurchase Program, up to an aggregate amount of $200.0 million. During the twelve months ended December 31, 2008, the Company paid $39.3 million to repurchase 1,030,145 shares of its common stock at an average price of $38.11 pursuant to the Repurchase Program. During the twelve months ended December 31, 2007, the Company paid $35.3 million to repurchase 1,060,669 shares of its common stock at an average price of $33.24 per share under the Repurchase Program. At December 31, 2008, there was $113.6 million available for future repurchases under the Repurchase Program. Of the amount available for future repurchases, $100.0 million is subject to our meeting a maximum leverage ratio test of pro-forma net debt to adjusted EBITDA of less than 2.25 to 1.00 under our Senior Secured Credit Facility. The ratio test must be met at the time of each applicable share repurchase.

Covenant Compliance

Our indirect wholly-owned subsidiary, Foundation Coal Corporation is required to comply with certain financial covenants which are considered material terms of the Senior Secured Credit Facility and the indenture governing FCC's outstanding 7.25% Senior Notes. Information about the financial covenants is material to an investor's understanding of FCC's financial condition and liquidity. The breach of covenants in the Senior Secured Credit Facility that are tied to ratios based on Adjusted EBITDA, as defined below, could result in a default under the Senior Secured Credit Facility and the lenders could elect to declare all amounts borrowed due and payable. Any such acceleration would also result in a default under our indenture. Additionally, under the Senior Secured Credit Facility and indenture, FCC's ability to engage in activities such as incurring additional indebtedness, making investments and paying dividends is also tied to ratios based on Adjusted EBITDA.

Covenants and required levels as defined by the July 7, 2006 Senior Secured Credit Facility and the indenture governing the outstanding 7.25% Senior Notes are:

	Period Ended December 31, 2008 Covenant Levels	January 1, 2009 and thereafter Covenant Levels
Senior Secured Credit Facility		
Minimum Adjusted EBITDA to cash interest ratio	2.5x	2.5x
Maximum total debt less unrestricted cash to Adjusted EBITDA ratio	3.75x	3.5x
Indenture		
Minimum Adjusted EBITDA to fixed charge ratio required to incur additional debt pursuant to ratio provisions	2.0x	2.0x

Adjusted EBITDA is defined as EBITDA further adjusted to exclude non-recurring items, non-cash items and other adjustments permitted in calculating covenant compliance under the indenture and the Senior Secured Credit Facility. EBITDA, a measure used by management to evaluate its ongoing operations for internal planning and forecasting purposes, is defined as net income (loss) from operations plus interest expense, net of interest income, income tax expense (benefit), depreciation and amortization and charges for early extinguishment of debt. EBITDA is not a financial measure recognized under United States generally accepted accounting principles and does not purport to be an alternative to net income as a measure of operating performance or to cash flows from operating activities as a measure of liquidity. The amounts shown for EBITDA as presented, may differ from amounts calculated and may not be comparable to other similarly titled measures used by other companies.

As of December 31, 2008, FCC was in compliance with all required financial covenants of the Senior Secured Credit Facility.

Contractual Obligations

The following is a summary of our significant future contractual obligations by year as of December 31, 2008.

	2009	2010-2011	2012-2013	After 2013	Total
	(Unaudited, in thousands)				
Long-term debt	$ 16,750	$ 284,750	$ -	$ 298,285	$ 599,785
Estimated cash interest on long-term debt	30,129	54,622	43,251	21,626	149,628
Estimated cash payments for asset retirement obligations	5,595	12,389	2,628	235,181	255,793
Unconditional purchase commitments	197,625	13,716	-	-	211,341
Federal coal lease	36,108	72,216	36,108	-	144,432
Operating leases	3,786	2,992	1,477	2,124	10,379
Total	$ 289,993	$ 440,685	$ 83,464	$ 557,216	$1,371,358

We expect to use cash flows provided by operating activities to invest in the range of $190.0 million to $240.0 million in capital expenditures during calendar year 2009 of which $150.0 million to $180.0 million is to maintain production and replace mining equipment. The additional $40.0 million to $60.0 million is expected to be directed toward improvements in productivity and selective expansions of production. Approximately $61.7 million of the 2009 capital expenditures are included in unconditional purchase commitments shown above. The remaining 2009 unconditional purchase commitments consist of $56.1 million for purchased coal in normal quantities for delivery to customers and $79.8 million pertaining to forward contracts to purchase explosives and diesel fuel in normal quantities for use at our surface mines. We expect to contribute approximately $30.0 million to our defined benefit retirement plans and to pay approximately $26.0 million of retiree health care benefits, gross of Medicare Part D subsidies, in calendar year 2009. We also expect to incur approximately $6.0 million per year for surety bond premiums and letters of credit fees. We believe that cash balances plus cash generated by operations will be sufficient to meet these obligations plus fund requirements for working capital and capital expenditures without incurring additional borrowings. However, if additional borrowings are needed, the Company would plan to utilize amounts available under its revolving credit facility.

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 and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in our Consolidated Balance Sheets. However, the underlying obligations that they secure, such as asset retirement obligations, self-insured workers' compensation liabilities, royalty obligations and certain retiree medical obligations, are reflected in our Consolidated Balance Sheets.

We are required to provide financial assurance in order to perform the post-mining reclamation required by our mining permits, pay our federal production royalties, pay workers' compensation claims under self-insured workers' compensation laws in various states, pay federal black lung benefits, pay retiree health care benefits to certain retired UMWA employees and perform certain other obligations.

In order to provide the required financial assurance, we generally use surety bonds for post-mining reclamation and royalty payment obligations and bank letters of credit for self-insured workers' compensation obligations and UMWA retiree health care obligations. Federal black lung benefits are paid from a dedicated trust fund to which future contributions will be required. Bank letters of credit are also used to collateralize a portion of the surety bonds.

We had outstanding surety bonds with a total face amount of $300.3 million as of December 31, 2008, of which $275.2 million secured reclamation obligations; $15.7 million secured coal lease obligations; $7.1 million secured self-insured workers' compensation obligations; and $2.3 million for other miscellaneous obligations. In addition, we had $170.9 million of letters of credit in place for the following purposes: $39.1 million for workers' compensation, including collateral for workers' compensation bonds; $8.1 million for UMWA retiree health care obligations; $117.1 million for collateral for reclamation surety bonds; and $6.6 million for other miscellaneous obligations. In the last few years, the market terms under which surety bonds can be obtained have generally become less favorable to all mining companies. In the event that additional surety bonds become unavailable, we would seek to secure our obligations with letters of credit, cash deposits or other suitable forms of collateral.

Wage Negotiations with the UMWA and Idling of the Company's Illinois Basin Mining Operation

Wage agreements between three affiliates of the Company and the UMWA expired on or shortly after March 31, 2007. The hourly workforce continued to work without a formal agreement of the parties under the terms of the expired wage agreement until 12:01 a.m. on April 4, 2007 at which time, alleging unfair labor practices by Wabash, Emerald and Cumberland, the UMWA represented hourly workforces struck the Wabash, Emerald and Cumberland mines. Subsequent to the commencement of a UMWA strike on April 4, 2007, Wabash announced the idling of the mine in southern Illinois. The mine had become economically unviable at that time as a result of a combination of factors, including aged infrastructure, softening market conditions and the prospect of a new higher cost labor contract with the UMWA.

As a result of the Wabash idling, the Company recognized employee termination costs of $6.0 million and $1.3 million in accordance with the provisions of SFAS No. 146 and the provisions of SFAS No. 112, respectively, during the twelve months ended December 31, 2007. Termination costs resulting from one-time benefit arrangements include medical insurance continuance costs and severance to salaried employees. During the twelve months ended December 31, 2007, the Company also recognized $2.0 million of direct and incremental costs related to additional benefit claims for certain severed employees. Additionally, the Company recorded contract termination costs of $5.2 million associated with the idling of the mine. These costs are recorded as *Employee and contract termination costs and other* in the Consolidated Statements of Operations and Comprehensive (Loss) Income.

Certain Trends and Uncertainties

Our long-term outlook for the coal markets in the U.S. remains positive. The Energy Information Administration in its Annual Energy Outlook—2009 forecasts that coal-fired electrical generation will increase by an average annual growth rate of 0.7% through 2015. For 2008, electric power generation from coal decreased 1.3% compared to 2007 as overall U.S. demand for electricity declined during that period. Long-term demand for coal and coal-based electricity generation in the U.S. will likely be driven by various factors such as the declining and rebounding economy, increasing population, increasing demand to power residential electronics, public demands for affordable electricity, relatively high prices for the alternative fossil fuels of gas and oil for electricity generation, the inability for renewable energy sources such as wind and solar to become the base load source of electric power, geopolitical risks for continuing to import large quantities of global oil and natural gas resources, increasing demand for coal outside the U.S. resulting in increased exports and the relatively abundant steam coal reserves located within the United States. Despite the recent downturn to the U.S. and global economies, the October 2008 International Monetary Fund forecast for U.S. annual GDP growth averages over 2% for the next five years.

According to the Ventyx Velocity Suite, a database used by the U.S. Department of Energy to track new coal-fired power plants, there are approximately 16,901 megawatts of new coal-fired electrical generation under construction in the United States. There are an additional 2,812 megawatts near construction and 7,000 megawatts of new coal-fired electrical generating capacity permitted and expected to be constructed. This new capacity will increase the annual coal consumption for electrical generation by an estimated ninety million tons, much of which is expected to be supplied from the Powder River Basin in Wyoming. Approximately 31,869 megawatts of additional coal-fired electrical generation has been announced and is in the early stages of permitting and development.

During 2008 coal exports from the U.S. increased significantly in response to strong worldwide demand for coal. The largest increases in international coal demand are from the rapidly growing and industrializing economies of China and India. Due partly to weather-related and infrastructure constraints in Australia and reduced exports from South Africa and other coal exporting countries, the seaborne coal trade has struggled to keep up with these increases in demand. Seaborne coal shipments traditionally destined for Europe have been diverted to Asia creating opportunities to increase exports from the United States. Coal export volumes increased nearly 20% in 2007 compared to 2006. Export volumes for 2008 increased by approximately 40% to roughly 86 million tons, levels last seen over a decade ago. Although demand for US export coal will decline in 2009, it is expected that volumes will remain close to 2007 levels due to the number of committed tons under contract. According to the World Energy Outlook 2008 ("WEO"), global primary energy demand will grow by more than 41% by 2030, with coal demand rising most in absolute terms and fossil fuel accounting for most of the increase in demand between now and 2030. China and India have contributed more than half the increase in global demand for energy, and over 80% for coal, since 2000. The WEO estimates these two growing economies will contribute more than 50% of the increase in global energy demand and over 85% of the increase in global coal demand through 2030. The WEO has reached a general conclusion that dependence on coal for power rises strongly in countries with emerging economies and relatively large coal reserves, while it stagnates in the more developed nations and nations with smaller coal reserves.

Ultimately, the global demand for and use of coal may be limited by any global treaties which place restrictions on carbon dioxide emissions. As part of the United Nations Framework Convention on Climate Change, representatives from 187 nations met in Bali, Indonesia in December 2007 to discuss a program to limit greenhouse gas emissions after 2012. The United States participated in the conference. The convention adopted what is called the "Bali Action Plan." The Bali Action Plan contains non-binding commitments, but concludes that "deep cuts in global emissions will be required" and provides a timetable for two years of talks to shape the first formal addendum to the 1992 United Nations Framework Convention on Climate Change treaty since the Kyoto Protocol. The ultimate outcome of the Bali Action Plan, and any treaty or other arrangement ultimately adopted by the United States or other countries, may have a material adverse impact on the global supply and demand for coal. This is particularly true if cost effective technology for the capture and storage of carbon dioxide is not sufficiently developed.

Proposed coal-fired electric generating facilities that do not include technologies to capture and store carbon dioxide are facing increasing opposition from environmental groups as well as state and local governments who are concerned with global climate change and uncertain financial impacts of potential greenhouse gas regulations. Coal-fired generating plants incorporating carbon dioxide capture and storage technologies are more expensive to build than conventional pulverized coal generating plants and the technologies are still in the developmental stages. This dynamic, coupled with the weakened short-term economic outlook, may cause power generating companies to cut back on plans to build coal-fired plants in the near term. Nevertheless, the desire to attain US energy independence ensures the construction of new coal-fired generating facilities will remain a viable option. In combination with heightened interest in coal gasification and coal liquefaction, this level of interest is a potential indicator of increasing demand for coal in the United States.

Based on weekly production reporting through December 31, 2008 from the Energy Information Administration, year-over-year Appalachian production has risen by approximately 2.9% as high prices encouraged increased output. Through 2008, Western coal production had increased approximately 2.4% from the prior year. In Central Appalachia, delays with respect to permits to construct valley fills at surface mines are likely to slow the permitting process for surface mining in that region with resultant uncertainties for producers. Average spot market prices for December 2008 for Central Appalachian and Northern Appalachian coals increased by roughly 20% and 35%, respectively, compared to the same month one year earlier. Average spot market prices for the month of December for Powder River Basin coal are up approximately 12% from the previous year, with the basin offering the least expensive fossil fuel on a dollar per Btu basis. Long-term, the delicate balance of coal supply and increasing coal demand is expected to result in strong, but volatile fundamentals for the U.S. coal industry.

Our revenues depend on the price at which we are able to sell our coal. The current pricing environment for U.S. steam coal production has fallen below the high levels seen during the summer of 2008, yet is strong in relation to historical pricing levels. Prices for high quality metallurgical coal, used to manufacture coke for steelmaking, have deteriorated in response to decreased worldwide demand for steel and destocking of metallurgical coal inventories.

The worldwide economic slowdown and the current volatility and uncertainty in the credit markets have had an impact on the demand and price of coal. Weakening global energy fundamentals, including the decline in demand and prices for both natural gas and crude oil have driven spot prices of coal lower in the financial markets. Steel manufacturers are shutting-in capacity due to the lack of near-term visibility around demand for steel for construction and other down-stream products. Steel manufacturers are destocking their current inventories of metallurgical coal in a move which is further weakening short-term demand for coal. A protracted economic slowdown could slacken demand for metallurgical and steam coals and could negatively influence pricing in the near-term. Longer-term, coal industry fundamentals remain intact. Coal has been the fastest growing fossil fuel for five consecutive years, and significant additional growth is expected worldwide. The seaborne coal market has grown to nearly 1 billion tons annually, and U.S. exports will be needed to meet worldwide demand. These factors should lead to a tighter market for coal, both globally and in the United States, in the coming years. While these threats are real and will impact coal pricing, we do not believe it will change the long-term view for coal.

Our results of operations are dependent upon the prices we charge for our coal as well as our ability to improve productivity and control costs. We spend more than $600 million per year to procure goods and services in support of our business activities, excluding capital expenditures. Principal goods and services include maintenance and repair parts and services, electricity, fuel, roof control and support items, explosives, tires, conveyance structure, ventilation supplies and lubricants. We use suppliers for a significant portion of our equipment rebuilds and repairs both on- and off-site, as well as construction and reclamation activities and to support computer systems.

The Company's management continues to aggressively control costs and strives to improve operating performance to mitigate external cost pressures. As with most of our competitors, we are experiencing volatility in operating costs related to fuel, explosives, steel, tires, contract services and healthcare and have taken measures to mitigate the increases in these costs at all operations. Each of our regional mining operations has developed its own supplier base consistent with local needs. We have a centralized sourcing group for major supplier contract negotiation and administration, for the negotiation and purchase of major capital goods, and to support the business units. The supplier base has been relatively stable for many years, but there has been some consolidation. We are not dependent on any one supplier in any region. We promote competition between suppliers and seek to develop relationships with those suppliers whose focus is on lowering our costs. We seek suppliers who identify and concentrate on implementing continuous improvement opportunities within their area of expertise. To the extent upward pressure on costs exceeds our ability to realize sales increases, or if we experience unanticipated operating or transportation difficulties, our operating margins would be negatively impacted. Employee labor costs have increased primarily due to the demands associated with attracting and retaining a stable workforce. We may also continue to experience difficult geologic conditions, delays in obtaining permits, labor shortages, unforeseen equipment problems and shortages of critical materials such as tires and explosives that may limit our ability to produce at forecasted levels.

Critical Accounting Estimates

Our financial statements are prepared in accordance with accounting principles that are generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management evaluates its estimates on an on-going basis. Management bases its estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Actual results may differ from the estimates used. Note 2 to the consolidated financial statements provides a description of all significant accounting policies. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity.

Asset Retirement Obligations

Our asset retirement obligations arise from The Surface Mining Control and Reclamation Act of 1977 (the "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. Reclamation activities that are performed outside of the normal mining process are accounted for as asset retirement obligations in accordance with the provisions of SFAS No. 143. We determine the future cash flows necessary to satisfy our reclamation obligations on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage, cost estimates and assumptions regarding productivity. Estimates of disturbed acreage are determined based on approved mining plans and related engineering data. Cost estimates are based on historical or third-party costs, both of which are stated at fair value. Productivity assumptions are based on historical experience with the equipment that is expected to be utilized in the reclamation activities. In accordance with the provisions of SFAS No. 143, we determine the fair value of our asset retirement obligations. In order to determine fair value, we must also estimate a discount rate and third-party margin. Each is discussed below:

- Discount rate—SFAS No. 143 requires that asset retirement obligations be recorded at fair value. In accordance with the provisions of SFAS No. 143, we utilize discounted cash flow techniques to estimate the fair value of our obligations. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives adjusted for our credit standing.
- Third party margin—SFAS No. 143 requires the measurement of an obligation to be based on the amount a third party would demand to assume the obligation. Because we plan to perform a significant amount of the reclamation activities with internal resources, a third-party margin was added to the estimated costs of performing these activities with internal resources. This margin was estimated based upon discussion with contractors that perform reclamation activities. If our cost estimates are accurate, the excess of the recorded obligation over the cost incurred to perform the work will be recorded as a gain at the time that reclamation work is settled.

On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, additional costs resulting from accelerated mine closures, and revision to cost estimates and productivity assumptions, in each case to reflect current experience.

At December 31, 2008, we had recorded asset retirement obligation liabilities of $171.4 million, including amounts reported as current. While the precise amount of these future costs cannot be determined with certainty, we estimate that the aggregate undiscounted cost of final mine closure is approximately $254.6 million at December 31, 2008 payable through 2036.

Employee Benefit Plans

We have two non-contributory defined benefit retirement plans covering certain of our salaried and non-union hourly employees. We also have an unfunded non-qualified Supplemental Executive Retirement Plan covering certain eligible employees. Benefits are based on either the employee's compensation prior to retirement or stated amounts for each year of service with us. Funding of these plans is in accordance with the requirements of ERISA, which can be deducted for federal income tax purposes. We contributed $11.3 million into the plans for the twelve months ended December 31, 2008 and 2007. We account for our defined benefit retirement plans in accordance with SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158") which requires amounts recognized in the financial statements to be determined on an actuarial basis. For the twelve months ended December 31, 2008, 2007 and 2006, we recorded pension expense of $7.5 million, $7.0 million and $7.2 million, respectively.

The calculation of the net periodic benefits costs (pension expense) and projected benefit obligation associated with our defined benefit pension plans requires the use of a number of assumptions that we deem to be "critical accounting estimates." These assumptions are used by our independent actuaries to make the underlying calculations. 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 of the rate of return on plan assets 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 57% equity/private equity, 28% fixed income, 9% other and 6% real estate mutual funds. Investments are rebalanced on a periodic basis to stay within these targeted guidelines. The long-term rate of return assumption used to determine periodic pension expense was 8% for the twelve months ended December 31, 2008, 2007 and 2006. Any difference between the actual experience and the assumed experience is deferred as an unrecognized actuarial gain or loss and amortized into expense in future periods.
- 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, SFAS No. 87, *Employers' Accounting for Pensions,* requires rates of return on high quality, fixed income investments. The discount rate used to determine pension expense was 6.25%, 5.9% and 5.6% for the twelve months ended December 31, 2008, 2007, and 2006, respectively. During 2007, actuarial liabilities related to our defined benefit plans were re-measured as of April 1, 2007 in connection with the idling of the Wabash mine. The discount rate was increased to 6.0% at that time. The differences resulting from actual versus assumed discount rates are amortized into pension expense over the remaining average service life of the active plan participants. A one half percentage-point increase in the discount rate would decrease the net periodic pension cost for the twelve months ended December 31, 2008 by approximately $0.1 million and decrease the projected benefit obligation at December 31, 2008 by approximately $12.5 million. The corresponding effects of a one half of one percentage-point decrease in the discount rate would be approximately a $0.1 million increase in the net periodic pension cost and approximately a $13.2 million increase in the projected benefit obligation.

We also currently provide certain postretirement medical and life insurance coverage for eligible employees. These obligations are unfunded. Covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. Postretirement medical plans for salaried employees and non-represented hourly employees are contributory, with retiree contributions adjusted annually, and contain other cost-sharing features such as deductibles. The postretirement medical plan for members of the UMWA is not contributory. We account for our other postretirement benefits in accordance with SFAS No. 158 which requires amounts recognized in the financial statements to be determined on an actuarial basis. For the twelve months ended December 31, 2008, 2007 and 2006, we recorded postretirement benefit expense of $39.8 million, $38.5 million and $39.3 million, respectively.

Various actuarial assumptions are required to determine the amounts reported as obligations and costs related to the postretirement benefit plan. The differences resulting from actual experience versus actuarial assumptions are deferred as unrecognized actuarial gains or losses and amortized into expense in future periods. These assumptions include the discount rate and the future medical cost trend rate.

- The discount rate assumption reflects the rates available on high quality fixed income debt instruments and is calculated in the same manner as discussed above for the defined benefit retirement plans. The discount rate used to calculate the postretirement benefit expense was 6.25%, 5.9% and 5.6% for the twelve months ended December 31, 2008, December 31, 2007 and December 31, 2006, respectively. During 2007, actuarial liabilities related to our postretirement benefit plans were re-measured as of April 1, 2007 in connection with the idling of the Wabash mine. The discount rate was increased to 6.0% at that time. A one half percentage-point increase in the discount rate would decrease the postretirement benefit expense for the twelve months ended December 31, 2008 by approximately $0.3 million and decrease the accumulated postretirement benefit obligation at December 31, 2008 by approximately $32.7 million. The corresponding effects of a one-half of one percentage-point decrease in the discount rate would be approximately a $0.2 million increase in the postretirement benefit expense and approximately a $34.7 million increase in the accumulated postretirement benefit obligation.

- The future health care cost trend rate represents the rate at which health care costs are expected to increase over the life of the plan. The health care cost trend rate assumptions are determined primarily based upon our historical rate of change in retiree health care costs. We have implemented many effective retiree health care cost containment measures that have resulted in actual increases in our retiree health care costs to fall far below the double-digit annual increases experienced by many companies and cited in most external studies. The postretirement expense for the twelve months ended December 31, 2008, 2007 and 2006 was based on an assumed initial health care inflationary rate of 8.0% for 2008 and 9.0% for 2007 and 2006, decreasing to 5.0% in 2015, 2011 and 2010, respectively, which represents the ultimate health care cost trend rate for the remainder of the plan life. A one-percentage point increase in the 5.0% assumed ultimate health care cost trend rate would increase the service and interest cost components of the postretirement benefit expense for the twelve months ended December 31, 2008 by $6.5 million and increase the accumulated postretirement benefit obligation at December 31, 2008 by $76.8 million. A one-percentage point decrease in the 5.0% assumed ultimate health care cost trend rate would decrease the service and interest cost components of the postretirement benefit expense for the twelve months ended December 31, 2008 by $5.2 million and decrease the accumulated postretirement benefit obligation at December 31, 2008 by $63.2 million.

Derivative Instruments and Hedging Activities

We are subject to the risk of price volatility for certain of the materials and supplies used in production, such as diesel fuel and explosives. As a part of our risk management strategy, we enter into pay fixed, receive variable swap agreements with financial institutions to mitigate the risk of price volatility for both diesel fuel and explosives. Swap agreements are derivative instruments accounted for in accordance with SFAS No. 133, which requires us to recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The requirements of SFAS No. 133 are complex and judgment is required in certain areas such as cash flow hedge accounting and hedge effectiveness testing. We assess each swap agreement to determine whether or not they qualify for special cash flow hedge accounting. In performing the assessment, we make estimates and assumptions about the timing and amounts of future cash flows related to the forecasted purchases of diesel fuel and explosives. We update our assessments at least on a quarterly basis.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), which requires the recognition of deferred tax assets and liabilities using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS No. 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors including the expected level of future taxable income and available tax planning strategies. At December 31, 2008, we had a full valuation allowance for deferred tax assets arising from Alternative Minimum Tax ("AMT") credits and a valuation allowance to reduce the value of our net deferred tax asset to an AMT tax rate. We also added a valuation allowance for the current year Federal net operating loss as well as valuation allowances for additional State net operating losses. We believe that we will continue to be an AMT tax payer indefinitely. If future taxable income is different than expected or if expected tax planning strategies are not available as anticipated, we may record a change to the valuation allowance through income tax expense in the period such determination is made.

Mineral Rights

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable mineral reserves. Many of these uncertainties are beyond our control. As a result, estimates of economically recoverable mineral reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff and independent third party consultants. Some of the factors and assumptions that impact economically recoverable reserve estimates include:

- geological and mining conditions;
- historical production from similar areas with similar conditions;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices;
- competing property rights such as surface rights, oil and gas rights, deeper or shallower coal rights and easements;
- ability to permit specific reserves for a particular type of mining;
- future operating, development and reclamation costs; and
- technology improvements.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows may vary substantially. Actual production, revenue and expenditures with respect to reserves may materially vary from estimates.

Recent Accounting Pronouncements

See Note 2 to the Consolidated Financial Statements in ITEM 8.

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

Price Risk

We manage our price risk for coal sales through the use of long-term coal supply agreements. As of January 26, 2009, we had sales commitments for approximately 97% of planned shipments for 2009. Uncommitted and unpriced tonnage was 3%, 41% and 71% for 2009, 2010 and 2011, respectively. The discussion below presents the sensitivity of the market value of our financial instruments to selected changes in market rates and prices. The range of changes reflects our view of changes that are reasonably possible over a one-year period. Market values are the present value of projected future cash flows based on the market rates and prices chosen.

We have exposure to price risk for supplies that are used directly or indirectly in the normal course of production such as diesel fuel, steel and other items such as explosives. We manage our risk for these items through strategic sourcing contracts in normal quantities with our suppliers and may use derivative instruments from time to time, primarily swap contracts with financial institutions, for a certain percentage of our monthly requirements. Swap agreements essentially fix the price paid for our diesel fuel and explosives by requiring us to pay a fixed price and receive a floating price.

We expect to use approximately 52,500 tons and 50,750 tons of explosives in 2009 and 2010, respectively. Through our derivative swap contracts, we have fixed prices for approximately 72% and 16% of our expected explosive needs for 2009 and 2010, respectively. At December 31, 2008, a $1.00 per MMBTU decrease in the price of natural gas would result in a $0.8 million increase in our expense in 2009 resulting from natural gas derivatives, which would be offset by a decrease in the cost of our physical explosive purchases.

We expect to use approximately 21,400,000 gallons and 19,500,000 gallons of diesel fuel in 2009 and 2010, respectively. Through our derivative swap contracts and physical forward contracts, we have fixed prices for approximately 85% and 16% of our expected diesel fuel needs for 2009 and 2010, respectively. At December 31, 2008, a $5.00 per barrel decrease in the price of oil would result in a $1.5 million increase in our expense in 2009 resulting from oil derivatives, which would be offset by a decrease in the cost of our physical diesel purchases.

Credit Risk

Our credit risk is primarily with electric power generators and, to a lesser extent, steel producers. Most electric power generators to whom we sell have investment grade credit ratings. Our policy is to independently evaluate each customer's creditworthiness prior to entering into transactions and to constantly monitor outstanding accounts receivable against established credit limits. When appropriate (as determined by our credit management function), we have taken steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or establishing customer trust accounts held for our benefit in the event of a failure to pay.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. We have exposure to changes in interest rates through our bank term loan and our revolving credit facility. To achieve risk mitigation objectives, we have in the past managed our interest rate exposure through the use of interest rate swaps.

The weighted average interest rate on the outstanding principal of our Senior Secured Credit Facility was 4.85% as of December 31, 2008. A hypothetical 1% increase in interest rates would have increased our interest expense approximately $3.0 million for the twelve months ending December 31, 2008. As we continue to monitor the interest rate environment in concert with our risk mitigation objectives, consideration is being given to future interest rate risk reduction strategies.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

FOUNDATION COAL HOLDINGS, INC. AND SUBSIDIARIES

CONSOLIDATED FINANCIAL STATEMENTS
INDEX

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

The 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 our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the consolidated 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.

Management assessed the effectiveness of the Company's internal controls over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in "Internal Control-Integrated Framework."

Based on our assessment and those criteria, management has concluded that the Company maintained effective internal control over financial reporting as of December 31, 2008.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2008 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Report of Independent Registered Public Accounting Firm – Internal Control Over Financial Reporting

The Board of Directors and Stockholders
Foundation Coal Holdings, Inc.

We have audited Foundation Coal Holdings, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Foundation Coal Holdings, Inc.'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.

In our opinion, Foundation Coal Holdings, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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 Foundation Coal Holdings, Inc. as of December 31, 2008 and 2007, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008 of Foundation Coal Holdings, Inc. and our report dated March 2, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Baltimore, Maryland
March 2, 2009

Report of Independent Registered Public Accounting Firm – Consolidated Financial Statements

The Board of Directors and Stockholders
Foundation Coal Holdings, Inc.

We have audited the accompanying consolidated balance sheets of Foundation Coal Holdings, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the index at Item 15 (a). 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 Foundation Coal Holdings, Inc. and subsidiaries at December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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.

As discussed in Note 2, on January 1, 2006, the Company adopted the provisions of EITF Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*. Also, as discussed in Note 2, on December 31, 2006, the Company adopted the provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. As discussed in Note 2, on January 1, 2007, the Company adopted the provisions of FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109.*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Foundation Coal Holdings, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Baltimore, Maryland
March 2, 2009

Foundation Coal Holdings, Inc. and Subsidiaries
Consolidated Balance Sheets
(Dollars in thousands, except per share data)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 42,326	$ 50,071
Trade accounts receivable	135,354	100,931
Inventories, net	56,508	44,122
Deferred income taxes, net	29,302	11,358
Prepaid expenses	28,517	30,534
Other current assets	5,676	6,678
Total current assets	297,683	243,694
Owned surface lands	51,802	36,807
Plant, equipment and mine development costs, net	685,609	664,429
Owned and leased mineral rights, net	888,514	928,439
Coal supply agreements, net	6,910	20,644
Other noncurrent assets	37,590	14,151
Total assets	$1,968,108	$1,908,164
LIABILITIES		
Current liabilities:		
Current portion of long-term debt	$ 16,750	$ -
Trade accounts payable	52,595	43,206
Accrued expenses and other current liabilities	202,752	160,991
Total current liabilities	272,097	204,197
Long-term debt	583,035	599,785
Deferred income taxes	-	3,161
Coal supply agreements, net	4,268	9,417
Postretirement benefits	533,166	505,787
Other noncurrent liabilities	351,181	249,480
Total liabilities	1,743,747	1,571,827
Commitments and contingencies (Note 27)		
STOCKHOLDERS' EQUITY		
Common stock, $0.01 par value; 100.0 million shares authorized, 47.0 million shares issued and 44.5 million shares outstanding at December 31, 2008; 46.4 million shares issued and 45.0 million shares outstanding at December 31, 2007	470	464
Additional paid-in capital	316,567	293,920
Retained earnings	89,329	86,800
Accumulated other comprehensive (loss) income	(93,378)	2,403
Treasury stock, at cost: 2.5 million shares at December 31, 2008; 1.4 million shares at December 31, 2007	(88,627)	(47,250)
Total stockholders' equity	224,361	336,337
Total liabilities and stockholders' equity	$1,968,108	$1,908,164

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

Foundation Coal Holdings, Inc. and Subsidiaries
Consolidated Statements of Operations and Comprehensive (Loss) Income
(Dollars in thousands, except per share data)

	Twelve Months Ended December 31,		
	2008	2007	2006
Revenues:			
Coal sales	$ 1,663,080	$ 1,452,702	$ 1,440,162
Other revenue	27,050	36,961	30,159
Total revenues	1,690,130	1,489,663	1,470,321
Costs and expenses:			
Cost of coal sales (excludes depreciation, depletion and amortization)	1,321,638	1,131,506	1,110,922
Selling, general and administrative expenses (excludes depreciation, depletion and amortization)	69,104	60,103	53,152
Accretion on asset retirement obligations	11,429	10,155	8,510
Depreciation, depletion and amortization	212,166	202,029	183,201
Amortization of coal supply agreements	1,368	(3,414)	(13,122)
Net change in fair value of derivative instruments	9,447	-	-
Employee and contract termination costs and other	-	14,656	-
Write-down of long-lived assets	-	-	30,782
Income from operations	64,978	74,628	96,876
Other income (expense):			
Interest expense	(46,960)	(53,666)	(64,525)
Mark-to-market loss on interest rate swaps	-	-	(112)
Interest income	992	3,531	3,011
Income before income tax (expense) benefit and equity in losses of affiliates	19,010	24,493	35,250
Income tax (expense) benefit	(6,646)	8,114	(3,831)
Equity in losses of affiliates	(810)	-	-
Net income	11,554	32,607	31,419
Other comprehensive (loss) income:			
Adjustments to unrecognized gains and losses and amortization of employee benefit plan costs, net of tax benefit of $24,337 in 2008 and tax expense of $23,806 in 2007	(80,526)	36,955	-
Unrealized loss on cash flow hedges, net of tax benefit of $4,131 in 2008 and $18 in 2007	(15,255)	(26)	-
Reclassification of unrealized gain on interest rate swaps into interest expense	-	(1,114)	11
Change in minimum pension liability, net of income tax expense of $960 in 2006	-	-	1,500
Unrealized gain on interest rate swaps, net of income tax expense of $90 in 2006	-	-	139
Comprehensive (loss) income	$ (84,227)	$ 68,422	$ 33,069
Basic earnings per common share	$ 0.26	$ 0.72	$ 0.69
Diluted earnings per common share	$ 0.25	$ 0.70	$ 0.67
Weighted-average shares-basic	45,073,432	45,156,659	45,397,370
Weighted-average shares-diluted	46,060,692	46,422,953	46,813,307
Dividends declared per share	$ 0.20	$ 0.20	$ 0.20

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

Foundation Coal Holdings, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity
(Dollars in thousands)

	Common Stock		Additional	Retained Earnings		Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Paid-In Capital	(Deficit)	Treasury Stock	Income (Loss)	Equity
Balance at December 31, 2005	44,685,733	$ 447	$ 259,426	$ 80,154	$ -	$ (777)	$ 339,250
Restricted stock issuance	15,000	-	-	-	-	-	-
Amortization of restricted stock	-	-	281	-	-	-	281
Equity-based compensation	-	-	2,699	-	-	-	2,699
Cash dividends declared and paid	-	-	-	(9,089)	-	-	(9,089)
Stock option exercises	1,054,908	11	7,554	-	-	-	7,565
Excess tax benefits from stock-based awards	-	-	9,476	-	-	-	9,476
Unrealized gain on interest rate swaps, net of tax	-	-	-	-	-	139	139
Termination of interest rate swaps	-	-	-	-	-	11	11
Shares repurchased	(323,000)	-	-	-	(11,889)	-	(11,889)
Adjustment to initially apply EITF 04- 6, net of tax at January 1, 2006	-	-	-	(39,264)	-	-	(39,264)
Change in minimum pension liability, net of tax	-	-	-	-	-	1,500	1,500
Adjustment to initially apply SFAS No. 158, net of tax, to defined benefit pension and postretirement plans as of December 31, 2006	-	-	-	-	-	(34,285)	(34,285)
Net income	-	-	-	31,419	-	-	31,419
Balance at December 31, 2006	45,432,641	$ 458	$ 279,436	$ 63,220	$ (11,889)	$ (33,412)	$ 297,813
Restricted stock issuance	10,500	-	-	-	-	-	-
Amortization of restricted stock	-	-	392	-	-	-	392
Equity-based compensation	-	-	6,178	-	-	-	6,178
Cash dividends declared and paid	-	-	-	(9,027)	-	-	(9,027)
Stock option exercises	603,885	6	4,622	-	-	-	4,628
Restricted stock units vested	7,000	-	-	-	-	-	-
Shares retired to treasury to satisfy minimum employee tax withholding on vested restricted stock units	(2,341)	-	-	-	(99)	-	(99)
Excess tax benefits from stock-based awards	-	-	3,292	-	-	-	3,292
Unrealized loss on cash flow hedges, net of tax	-	-	-	-	-	(26)	(26)
Reclassification of unrealized gain on interest rate swaps into interest expense	-	-	-	-	-	(1,114)	(1,114)
Shares repurchased	(1,060,669)	-	-	-	(35,262)	-	(35,262)
Adjustments to unrecognized gains and losses and amortization of employee benefit plan costs, net of tax	-	-	-	-	-	36,955	36,955
Net income	-	-	-	32,607	-	-	32,607
Balance at December 31, 2007	44,991,016	$ 464	$ 293,920	$ 86,800	$ (47,250)	$ 2,403	$ 336,337

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

Foundation Coal Holdings, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity—(Continued)
(Dollars in thousands)

	Common Stock		Additional Paid-In Capital	Retained Earnings (Deficit)	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount					
Balance at December 31, 2007	44,991,016	$ 464	$ 293,920	$ 86,800	$ (47,250)	$ 2,403	$ 336,337
Restricted stock issuance	10,500	-	-	-	-	-	-
Amortization of restricted stock	-	-	574	-	-	-	574
Equity-based compensation	-	-	13,043	-	-	-	13,043
Cash dividends declared and paid	-	-	-	(9,025)	-	-	(9,025)
Stock option exercises	511,405	5	3,723	-	-	-	3,728
Restricted stock units vested	112,718	1	(1)	-	-	-	-
Shares retired to treasury to satisfy minimum employee tax withholding on vested restricted stock units	(39,669)	-	-	-	(2,114)	-	(2,114)
Excess tax benefits from stock-based awards	-	-	5,308	-	-	-	5,308
Unrealized loss on cash flow hedges, net of tax	-	-	-	-	-	(15,255)	(15,255)
Shares repurchased	(1,030,145)	-	-	-	(39,263)	-	(39,263)
Adjustments to unrecognized gains and losses and amortization of employee benefit plan costs, net of tax	-	-	-	-	-	(80,526)	(80,526)
Net income	-	-	-	11,554	-	-	11,554
Balance at December 31, 2008	44,555,825	$ 470	$ 316,567	$ 89,329	$ (88,627)	$ (93,378)	$ 224,361

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

Foundation Coal Holdings, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(Dollars in thousands)

	Twelve Months Ended December 31,		
	2008	2007	2006
Operating activities:			
Net income	$ 11,554	$ 32,607	$ 31,419
Adjustments to reconcile net income to net cash provided by operating activities:			
Accretion on asset retirement obligations	11,429	10,155	8,510
Depreciation, depletion and amortization	213,534	198,615	170,079
Amortization of deferred financing costs	1,834	2,137	11,653
Gain on sale of assets	(1,565)	(5,185)	(876)
Non-cash stock compensation	13,617	6,570	3,046
Excess tax benefit from stock-based awards	(5,308)	(3,292)	(9,476)
Non-cash mark-to-market adjustment for interest rate swaps	-	-	112
Write-down of long-lived assets	-	-	30,782
Deferred income taxes	(6,666)	(23,712)	(25,657)
Asset retirement obligations	(3,288)	(628)	(2,567)
Equity in losses of affiliates	810	-	-
Unrealized mark-to-market loss on derivative instruments	9,447	-	-
Non-cash interest expense and other	2,473	(1,169)	1,275
Changes in operating assets and liabilities:			
Trade accounts receivable	(34,423)	18,672	(9,478)
Inventories, net	(12,473)	(7,224)	(1,942)
Prepaid expenses and other current assets	2,225	(3,205)	(9,595)
Other noncurrent assets	782	823	1,218
Trade accounts payable	9,389	(2,495)	6,200
Accrued expenses and other current liabilities	11,811	842	(12,482)
Noncurrent liabilities	8,956	17,452	33,445
Net cash provided by operating activities	234,138	240,963	225,666
Investing activities:			
Purchases of property, plant, equipment and mine development costs	(156,929)	(174,394)	(187,217)
Purchases of mining assets	-	-	(14,661)
Acquisition of mineral rights under federal lease	(36,108)	-	-
Purchases of equity-method investments	(10,275)	-	-
Proceeds from disposition of property, plant and equipment	2,795	8,917	2,010
Net cash used in investing activities	(200,517)	(165,477)	(199,868)
Financing activities:			
Payment of cash dividends	(9,025)	(9,027)	(9,089)
Proceeds from issuance of common stock	3,728	4,628	7,565
Excess tax benefit from stock-based awards	5,308	3,292	9,476
Proceeds from revolving credit facility	16,000	-	-
Principal repayments of revolving credit facility	(16,000)	-	-
Interest rate swap termination	-	-	2,259
Payment of deferred financing costs	-	-	(4,457)
Repayment of long-term debt	-	(26,784)	(8,375)
Common stock repurchases	(39,263)	(35,262)	(11,889)
Other	(2,114)	4,018	-
Net cash used in financing activities	(41,366)	(59,135)	(14,510)
Net (decrease) increase in cash and cash equivalents	(7,745)	16,351	11,288
Cash and cash equivalents at beginning of period	50,071	33,720	22,432
Cash and cash equivalents at end of period	$ 42,326	$ 50,071	$ 33,720
Supplemental cash flow information:			
Cash paid for interest	$ 40,337	$ 47,075	$ 48,611
Cash paid for income taxes, net of refunds	$ 12,301	$ 12,220	$ 17,283

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

Foundation Coal Holdings, Inc. and Subsidiaries
Notes to Consolidated Financial Statements
(Dollars in thousands)

Note 1. Description of Business

Foundation Coal Holdings, Inc. and its indirect subsidiary, Foundation Coal Corporation ("FCC"), were formed to acquire the North American coal mining assets of RAG American Coal Holding, Inc., which acquisition closed on July 30, 2004 (the "Acquisition"). Foundation Coal Holdings, Inc. and Subsidiaries (the "Company") operate a diverse group of twelve individual coal mines located in Wyoming, Pennsylvania and West Virginia. The Company, through its affiliates, engages in the extraction, cleaning and selling of coal to electric utilities, steel companies, coal brokers and industrial users primarily in the United States. The Company, through its affiliates, is also involved in marketing coal produced by others to supplement the its own production and, through blending, provide its customers with coal qualities beyond those available from its own production.

At December 31, 2008, union representation accounted for approximately 34% of the Company's employees. Labor contracts for the Pennsylvania mines, Emerald and Cumberland, with the United Mine Workers of America ("UMWA") were signed in 2007 and expire on December 31, 2011. The contract for the Wabash mine expired on March 31, 2007.

Note 2. Summary of Significant Accounting Policies

Principles of Consolidation

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

Use of Estimates

The Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the Company's consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The more significant areas requiring the use of management estimates and assumptions relate to coal reserves that are the basis for future cash flow estimates and units-of-production depreciation, depletion and amortization calculations; environmental and reclamation obligations; asset impairments; postemployment, postretirement and other employee benefit liabilities; valuation allowances for deferred income taxes; reserves for contingencies and litigation and the fair value and accounting treatment of certain financial instruments. Management bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Accordingly, actual results may differ significantly from these estimates. In addition, different assumptions or conditions could reasonably be expected to yield different results.

Cash and Cash Equivalents

Cash and cash equivalents consist of all cash balances and highly liquid investments. The Company's cash equivalents represent investments in a short-term US treasury securities money market fund consisting of 100% US treasury securities, which are used by the Company primarily for the overnight investment of excess cash. Because of the short maturity of these investments, the carrying amounts approximate their fair value.

Inventories and Stripping Costs

Coal inventories are valued at the lower of average cost or market. Market represents the estimated future sales price of the product based on prevailing and long-term prices, less the estimated preparation and selling costs.

Material and supplies inventories are valued at average cost, less an allowance for obsolete and surplus items.

The Company adopted Emerging Issues Task Force ("EITF") Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry* ("EITF Issue 04-6") on January 1, 2006. EITF Issue 04-6 addresses the accounting for stripping costs incurred during the production phase of a mine, concluding that these costs are considered variable production costs and under a full absorption costing system are considered a component of inventory to be recognized in cost of coal sales in the same period as the revenue from the sale of the inventory. Capitalization of post-production stripping costs is appropriate only to the extent inventory exists at the end of a reporting period. The guidance required initial application through recognition of a cumulative effect adjustment to opening retained earnings in the period of adoption, with no charge to current earnings for prior periods. The effect on the consolidated financial statements upon adoption of EITF Issue 04-6 resulted in a cumulative effect adjustment which reduced opening retained earnings, as of January 1, 2006, by $39,264, net of tax, thereby removing the asset previously classified on the Consolidated Balance Sheets as a component of work-in-process (deferred overburden) inventory.

Prepaid Expenses

Prepaid expenses consist primarily of deferred longwall move costs, advance mining royalties, prepaid taxes and prepaid insurance premiums. The Company defers the direct costs, including labor and supplies, associated with moving longwall equipment and the related equipment refurbishment costs in *Prepaid expenses.* These deferred costs are amortized on a units-of-production basis over the life of the subsequent panel of coal mined by the longwall equipment. Deferred costs that are anticipated to be amortized into production within one year are included in current assets. All other deferred costs are included in *Other noncurrent assets.*

Owned and Leased Mineral Rights

Costs to obtain coal lands and leased mineral rights are capitalized based on the fair value at acquisition and amortized to operations as depletion expense using the units-of-production method. Only proven and probable reserves are included in the depletion base. Depletion expense is included in *Depreciation, depletion and amortization* on the accompanying Consolidated Statements of Operations and Comprehensive (Loss) Income.

Plant, Equipment and Mine Development Costs

Costs of developing new mines or significantly expanding the capacity of or extending the lives of existing mines are capitalized and amortized using the units-of-production method over proven and probable reserves directly benefiting from the capital expenditure. Mobile mining equipment and other fixed assets are stated at cost and depreciated on a straight-line basis over the estimated useful lives ranging from 1 to 20 years or on a units-of-production basis. Leasehold improvements are amortized over their estimated useful lives or the term of the lease, whichever is shorter. Major repairs and betterments that significantly extend original useful lives or improve productivity are capitalized and depreciated over the period benefited. Maintenance and repairs are generally expensed as incurred.

The Company capitalizes certain costs incurred in the development of internal-use software, including external direct material and service costs, and employee payroll and payroll-related costs in accordance with the

American Institute of Certified Public Accountants' Statement of Position 98-1, "*Accounting for the Costs of Computer Software Developed for or Obtained for Internal Use.*" All capitalized internal-use software costs are amortized using the straight-line method over the estimated useful life not to exceed 7 years.

Asset Retirement Obligations

Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"), addresses a uniform methodology for accounting for estimated reclamation and abandonment costs. The Company's asset retirement obligations consist principally of costs to reclaim acreage disturbed at surface operations and estimated costs to reclaim support acreage and perform other related functions at underground mines. SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which the legal obligation associated with the retirement of the tangible long-lived asset is incurred. When the liability is initially recorded, the offset is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. To settle the liability, the obligation is paid, and to the extent there is a difference between the liability and the amount of cash paid, a gain or loss upon settlement is incurred. The Company estimates its asset retirement obligation liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of future cash flows required for a third party to perform the necessary reclamation work. The Company annually reviews the estimated future cash flows for its asset retirement obligations.

Coal Supply Agreements

Coal supply agreements represent the fair value assigned at the Acquisition date for acquired sales contracts. These sales contracts are valued at the present value of the difference between the expected contract revenues from the acquired contract, net of royalties and taxes imposed on sales revenues, and the net contract revenues derived from applying market prices at the Acquisition date for new contracts of similar duration and coal qualities. Using this approach to valuation, certain contracts, where the expected contract price is above market at the Acquisition date, have a positive value and are classified as assets. Certain other contracts, where the expected contract price is below market at the Acquisition date, have a negative value and are classified as liabilities. The asset or liability is amortized over the term of the contracts based on the tons of coal shipped under each contract. During 2008, the amortization of coal supply agreements was a $1,368 net debit, which consisted of a $6,516 expense related to the amortization of contract assets and a ($5,148) credit related to the amortization of contract liabilities. As of December 31, 2008, total accumulated amortization of the contract assets and contract liabilities was $83,557 and $250,866, respectively. As of December 31, 2007, total accumulated amortization of the contract assets and contract liabilities was $77,041 and $245,718, respectively. Based on expected future shipments under these agreements, amortization of the asset for above market contracts is anticipated to be approximately $3,579 and $3,331 for the years ended December 31, 2009 and 2010, respectively. Amortization of the liability for below market contracts is anticipated to be approximately ($3,316) and ($952) for the years ended December 31, 2009 and 2010, respectively.

Asset Impairment and Disposal of Long-lived Assets

The Company reviews and evaluates its long-lived assets and certain identifiable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the asset to future net undiscounted cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

Income Taxes

Income taxes are accounted for under the asset and liability method in accordance with SFAS No. 109, Accounting for Income Taxes ("SFAS No. 109"). Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and the respective tax bases for such assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in operations in the period that includes the enactment date.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. ("FIN") 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 ("FIN 48"), which clarifies the accounting for uncertainty in income taxes recognized in a company's consolidated financial statements in accordance with SFAS No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires an entity to recognize the financial statement impact of a tax position when it is more-likely-than-not that the position will be sustained upon examination. If the tax position meets the more-likely-than-not recognition threshold, the tax effect is recognized at the largest amount of the benefit that is greater than fifty percent likely of being realized upon ultimate settlement. FIN 48 requires that a liability created for unrecognized tax benefits shall be presented as a liability and not combined with deferred tax liabilities or assets.

The Company adopted FIN 48 on January 1, 2007. The cumulative effect of the adoption of FIN 48 was zero. The Company's gross tax-effected unrecognized tax benefits at the date of adoption were $9,671. The Company recognizes interest and penalties accrued related to unrecognized tax benefits as a component of tax expense. See Note 19 for further information.

During 2008, the Internal Revenue Service completed its examination of the Company's 2005 federal tax return. No changes were made to the Company's 2005 federal tax return with respect to this examination. Also, the Company has not received a notification from any state income tax authority regarding an audit that is planned to be scheduled, nor did it have an outstanding state tax examination in process at December 31, 2008.

A valuation allowance is provided to reduce deferred tax assets if, in management's judgment, it is more-likely-than-not that some portion of the deferred tax assets will not be realized.

Advance Mining Royalties

Leased mineral rights are often acquired through royalty payments. Advance mining royalties are advance payments made to lessors under terms of mineral lease agreements that are recoverable against future production. These advance payments are deferred and charged to operations as the coal reserves are mined. In instances where advance payments are not expected to be recoverable against future production, no asset is recognized and the scheduled future payments are expensed as incurred. Deferred advance mining royalties are recorded in *Prepaid expenses* and *Other noncurrent assets* on the Consolidated Balance Sheets.

Revenue Recognition

The Company recognizes revenue for sold coal when it has evidence of an agreement with a customer, the product has been delivered to the customer, the sales price is fixed and determinable and collectibility is reasonably assured. Delivery generally occurs when the coal is loaded into transport carriers for shipment to the customer.

Freight Revenue and Costs

Shipping and handling costs paid to third-party carriers and invoiced to coal customers are recorded and included in *Cost of coal sales* and *Coal sales revenue*, respectively.

Workers' Compensation

The Company is primarily self-insured for workers' compensation claims in the various states in which it operates. The liability for workers' compensation claims is an actuarially determined estimate of the undiscounted ultimate losses incurred on known claims plus a provision for incurred but not reported claims. This probable ultimate liability is re-determined semi-annually and resultant adjustments are expensed. These obligations are included in the Consolidated Balance Sheets as *Accrued expenses and other current liabilities* and *Other noncurrent liabilities*.

Pension, Other Postretirement Plans and Pneumoconiosis Benefits

Pension benefits, postretirement benefits and postemployment benefits are reflected in the Company's consolidated financial statements and accounted for in accordance with SFAS No. 87, *Employers' Accounting for Pensions* ("SFAS No. 87"); SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* ("SFAS No. 106"); and SFAS No. 112, *Employers' Accounting for Postemployment Benefits* ("SFAS No. 112"), respectively, as amended by SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158"), in the year that the recognition provisions of SFAS No. 158 are initially applied. The pension and postretirement benefits are accounted for over the estimated service lives of the employees. The cost of providing certain postemployment benefits is generally recognized when the employee becomes entitled to the benefit.

In September 2006, the FASB issued SFAS No. 158, which requires an employer to recognize the overfunded or underfunded status of a defined benefit pension and other postretirement plans (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other comprehensive (loss) income. SFAS No. 158 requires the Company to initially recognize the funded status of a defined benefit pension and other postretirement plans and to provide the required disclosures as of the end of the first fiscal year ending after December 15, 2006. Additionally, for fiscal years ending after December 15, 2008, the Company is required to measure plan assets and benefit obligations as of the date of the Company's fiscal year-end statement of financial position rather than at an interim period. On December 31, 2006, the Company adopted the recognition and disclosure provisions of SFAS No. 158. On December 31, 2007, the Company adopted the measurement date provisions of SFAS No. 158, measuring plan assets and benefit obligations as of December 31, 2007. See Note 13 for further discussion of the effect of adopting SFAS No. 158 on the Company's consolidated financial statements.

The Company is required by federal and state statutes to provide benefits to employees for awards related to black lung. The Company is largely self-insured for these benefits and funds benefit payments through a

Section 501 (c) (21) tax-exempt trust fund. Provisions are made for estimated benefits based on annual evaluations prepared by independent actuaries. The Company follows SFAS No. 106 for purposes of accounting for its black lung liabilities and assets.

Derivative Instruments and Hedging Activities

Derivative instruments and hedging activities are accounted for in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activity* ("SFAS No. 133") (as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities* and SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities,* ("SFAS No. 161")). The provisions of SFAS No. 161 will be applied beginning January 1, 2009. SFAS No. 133 establishes accounting and reporting standards for derivative instruments and hedging activities and requires that entities recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value.

On the date a derivative instrument is entered into, the Company generally designates a qualifying derivative instrument as either a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge), or a hedge of the variability of cash flows to be received or paid related to a recognized asset or liability or forecasted transaction (cash flow hedge). The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as fair value or cash flow hedges to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of the related hedged items. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, the Company discontinues hedge accounting prospectively and records all future changes in fair value in current period earnings or losses.

For derivative instruments that have not been designated as cash flow hedges, changes in fair value are recorded in current period earnings or losses. For derivative instruments that have been designated as cash flow hedges, the effective portion of the changes in fair value are recorded in *Accumulated other comprehensive (loss) income* and any portion that is ineffective is recorded in current period earnings or losses. Amounts recorded in *Accumulated other comprehensive (loss) income* are reclassified to earnings or losses in the period the underlying hedged transaction affects earnings or when the underlying hedged transaction is no longer probable of occurring. For derivative instruments that have been designated as fair value hedges, changes in the fair value of the derivative instrument and changes in the fair value of the related hedged asset or liability or unrecognized firm commitment are recorded in current period earnings or losses.

Stock-Based Compensation

Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123 (revised 2004), *Share-Based Payment* ("SFAS No. 123(R)"), using the modified prospective transition method. Under the modified prospective transition method, compensation cost recognized includes: (a) compensation cost for all stock-based awards granted prior to but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, *Accounting for Stock-Based Compensation,* ("SFAS No. 123"); and (b) compensation cost for all stock-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results from prior periods have not been restated. For all grants, the amount of compensation expense to be recognized is adjusted for an estimated forfeiture rate which is based on historical data.

Compensation expense for awards with cliff vesting provisions is recognized on a straight-line basis from the measurement date through the vesting date. Compensation expense for awards with graded vesting provisions is recognized using the accelerated attribution method.

Earnings Per Share

Basic earnings per share is computed by dividing net income by the weighted-average number of outstanding common shares for the period. Diluted earnings per share reflects the potential dilution that could occur if instruments that may require the issuance of common shares in the future were settled and the underlying common shares were issued. Diluted earnings per share is computed by increasing the weighted-average number of outstanding common shares to include the additional common shares that would be outstanding after issuance and adjusting net income for changes that would result from the issuance. Only those securities that result in a reduction in earnings per share are included in the calculation. See Note 20 for the dilutive impact of stock options and restricted stock plans on the earnings per share calculation.

Other Comprehensive (Loss) Income

In addition to net income, other comprehensive (loss) income includes changes to *Accumulated other comprehensive (loss) income* such as: adjustments to unrecognized gains and losses and amortization of employee benefit plan costs; the effective portion of changes in fair value of derivative instruments that qualify as cash flow hedges; and adjustments to minimum pension liabilities prior to the adoption of the recognition provisions of SFAS No. 158.

Debt Issuance Costs

Costs incurred in connection with the issuance of the certain debt facilities were capitalized and are being amortized over a weighted-average term, reflective of the lives of the related indebtedness ranging between 5 to 10 years, using the effective interest method.

New Pronouncements

In December 2008, the FASB issued FASB Staff Position ("FSP") No. 132(R)-1 *Employers' Disclosures about Postretirement Benefit Plan Assets* ("FSP FAS 132(R)-1"). This FSP amends FASB Statement No. 132 (revised 2003), *Employers' Disclosures about Pension and Other Postretirement Benefits*, ("SFAS No. 132(R)"), to provide guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. The additional disclosure requirements under this FSP include expanded disclosures about an entity's investment policies and strategies, the categories of plan assets, concentrations of credit risk and fair value measurements of plan assets. FSP 132(R)-1 will be effective for fiscal years ending after December 15, 2009. The Company expects to adopt FSP 132(R)-1 on January 1, 2009 and does not believe it will have a material impact on its consolidated financial statements.

In June 2008, the FASB issued FSP Emerging Issues Task Force 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP 03-6-1"). This FSP provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. FSP 03-6-1 will be effective for fiscal years beginning after December 15, 2008 and interim periods within those years. Early adoption is not permitted. All prior year EPS data presented is required to be adjusted retrospectively. The Company expects to adopt FSP 03-6-1 on January 1, 2009 and does not believe it will have a material impact on its consolidated financial statements.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* ("SFAS No. 162"). This standard identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles. SFAS No. 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles*. The Company expects to adopt SFAS No. 162 when it becomes effective and does not believe it will have a material impact on its consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161. This standard amends and expands the disclosure requirements of SFAS No. 133 and establishes, among other things, the disclosure requirements for derivative instruments and for hedging activities. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008. The Company expects to adopt SFAS No. 161 on January 1, 2009 and does not believe it will have a material impact on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* ("SFAS No. 160"). This standard outlines the accounting and reporting for ownership interest in a subsidiary held by parties other than the parent. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. The Company expects to adopt SFAS No. 160 on January 1, 2009 and does not believe it will have a material impact on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations* ("SFAS No. 141(R)"). This standard establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. This statement also establishes disclosure requirements which will enable users to evaluate the nature and financial effects of the business combination. SFAS No.141(R) is effective for acquisitions for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141(R) changes the accounting after the acquisition date for reductions in valuation allowances established in purchase price allocation related to an acquired entity's deferred assets; including those relating to acquisitions prior to the adoption of SFAS No. 141(R). Effective from the date of adoption of SFAS No. 141(R), the effects of reductions in valuation allowances established in purchase accounting that are outside of the measurement period are reported as adjustments to income tax expense. The Company expects to apply the provisions of SFAS No. 141(R) effective January 1, 2009 and has not yet determined the impact from the adoption of this new accounting pronouncement on its consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157") which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 clarifies how to measure fair value as required or permitted under other accounting pronouncements but does not require any new fair value measurements. SFAS No. 157 was originally effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. On February 12, 2008, the FASB issued FSP No. Financial Accounting Standard 157-2, *Effective Date of FASB Statement No. 157* ("FSP No. 157-2"). FSP No. 157-2 was effective upon issuance and delayed the effective date of SFAS No. 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis or at least once a year, to fiscal years beginning after November 15, 2008. The provisions of FSP No. 157-2 are effective for the Company's fiscal year beginning January 1, 2009. On October 10, 2008, the FASB issued FASB FSP No. Financial Accounting Standard 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* ("FSP No. 157-3"). FSP No. 157-3 clarifies the application of SFAS No. 157 in determining the fair value of a financial asset when the market for that financial asset is not active. FSP No. 157-3 became effective upon issuance, including interim periods for which financial statements have not been issued. The Company adopted FSP No.157-3 upon issuance.

(Dollars in thousands)

The Company adopted the provisions of SFAS No. 157 on January 1, 2008. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Inputs are either observable or unobservable and refer broadly to the assumptions that are used in pricing assets or liabilities. Observable inputs are reflective of market data and unobservable inputs reflect the entity's own assumptions about pricing assets or liabilities. As defined below, the fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy under SFAS 157 are further described as follows:

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities;

Level 2 Quoted prices for identical or similar assets or liabilities in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability, or by market-corroborated inputs;

Level 3 Unobservable inputs for the assets or liability in which the fair value measurement is supported by little or no market activity but reflects the best information available to the reporting entity and may include the entity's own data.

These levels are not necessarily an indication of the risk or liquidity associated with the financial assets or liabilities disclosed.

The following table sets forth the Company's financial assets and liabilities measured at fair value by level within the fair value hierarchy at December 31, 2008. As required by SFAS No. 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Level 1	Level 2	Level 3
Cash equivalents	$ 42,326	-	-
Sulfur dioxide emission allowances	-	$ 544	-
Derivative instruments	-	$ 28,877	-

The Company's cash equivalents represent investments in a short-term US treasury securities money market fund consisting of 100% US treasury securities, which are used by the Company primarily for the overnight investment of excess cash and are classified within Level 1 of the fair value hierarchy. The instruments are valued based on unadjusted market prices in active markets for money market funds held on a short-term basis.

The Company's sulfur dioxide emission allowances ("emission allowances") are reported at fair value and are valued based on quoted prices in markets where there are fewer transactions as they are less actively traded due to the limited market for emission allowances. As such, the emission allowances are classified within Level 2 of the fair value hierarchy.

The Company's derivative instruments are reported at fair value, which are derived using valuation models commonly used for derivatives. Where possible, the Company verifies the values produced by such models to market prices. Valuation models require a variety of inputs, including contractual terms, market fixed prices, inputs from forward price yield curves, notional quantities, measures of volatility and correlations of such inputs. The inputs in such valuation models do not involve significant management judgment. Such instruments are typically classified within Level 2 of the fair value hierarchy.

Note 3. Employee and Contract Termination Costs

In April 2007, Wabash Mine Holding Company ("Wabash") announced the idling of the mine in southern Illinois. The mining operation had become economically unviable at that time. As a result of the Wabash mine idling, the Company recognized employee termination costs of $5,968 and $1,326 in accordance with the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* ("SFAS No. 146") and the provisions of SFAS No. 112, *Employers' Accounting for Postemployment Benefits* ("SFAS No. 112"), respectively, during the twelve months ended December 31, 2007. Additionally, the Company recognized $5,171 of net contract termination costs in accordance with the provisions of SFAS No. 146 during the twelve months ended December 31, 2007. Termination costs resulting from one-time benefit arrangements in accordance with SFAS No. 146 include medical insurance continuance costs and one-time retention pay to salaried employees. During the twelve months ended December 31, 2007, the Company also recognized $1,991 of direct and incremental costs related to additional benefit claims for certain severed employees. Employee and contract termination costs are recorded as *Employee and contract termination costs and other* in the Consolidated Statements of Operations and Comprehensive (Loss) Income for the twelve months ended December 31, 2007. Wabash is included in the Company's *Other* segment. See Note 21.

At December 31, 2008 and 2007, the Company's liability for employee termination costs were $110 and $214, respectively, and are included in *Accrued expenses and other current liabilities*.

Note 4. Write-down of Long-Lived Assets

In the fourth quarter of 2006, the Company recognized an asset impairment charge to write-down the carrying value of assets at its Wabash mine ("Wabash assets") to their estimated fair value and to write-off a prepaid royalty in Central Appalachia in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets*. These impairment charges are recorded as *Write-down of long-lived assets* on the Consolidated Statements of Operations and Comprehensive (Loss) Income. At the Wabash mine, the Company wrote down assets included in *Inventories, net; Owned surface lands; Plant, equipment and mine development costs, net and Owned and leased mineral rights, net,* in the Consolidated Balance Sheets by $1,517, $439, $21,686 and $5,730, respectively. The Company noted impairment indicators with respect to the Wabash assets and the on-going recoverability of the carrying value of the assets in the fourth quarter of 2006 based primarily upon its analysis of recent financial results. Analysis of these financial indicators as well as other non-financial indicators lead to management's decision, late in the fourth quarter of 2006, to discontinue additional capital expenditures related to an ongoing mine recapitalization and development project. In testing the recoverability of the carrying value of the Wabash assets and in assessing their fair value, the Company utilized a combination of cash flow projections, third party appraisals and other evidence of fair value, including an assessment of the assets' value in the open market. The Wabash assets are included in the Company's *Other* segment. See Note 21. In Central Appalachia as a result of a change in the Company's mine plan, the Company wrote-off $1,410 of prepaid royalties previously recorded in *Other noncurrent assets*. These royalties were associated with a lease under which future mining was determined to be not probable. This determination was made in the fourth quarter of 2006.

(Dollars in thousands)

Note 5. Significant Property Transactions

In the first quarter of 2008, Foundation Wyoming Land Company, an indirect wholly owned subsidiary of the Company, was the successful bidder on a new federal coal lease adjacent to the western boundary of the Eagle Butte mine located north of Gillette, Wyoming. The Company's lease bonus bid was $180,540, payable in five equal annual installments of $36,108. The Company made the first payment of $36,108 during the first quarter of 2008. The initial payment was capitalized as a component of *Owned and leased mineral rights, net* in the Consolidated Balance Sheets. Subsequent payments will be capitalized when paid. The lease became effective on May 1, 2008. This federal coal lease contains an estimated 224.0 million tons of proven and probable coal reserves.

Note 6. Inventories

Inventories consisted of the following at:

	December 31, 2008	December 31, 2007
Saleable coal	$ 21,013	$ 16,317
Raw coal	4,839	2,497
Materials and supplies	38,764	31,930
	64,616	50,744
Less materials and supplies reserve for obsolescence	(8,108)	(6,622)
	$ 56,508	$ 44,122

Saleable coal represents coal stockpiles ready for shipment to a customer. Raw coal represents coal that requires further processing prior to shipment.

Note 7. Prepaid Expenses

Prepaid expenses consisted of the following at:

	December 31, 2008	December 31, 2007
Prepaid royalties	$ 1,551	$ 1,358
Prepaid longwall move expenses	6,487	9,636
Prepaid SO_2 emission allowances	544	1,711
Prepaid taxes	9,071	5,803
Prepaid insurance	9,291	10,030
Other	1,573	1,996
	$ 28,517	$ 30,534

(Dollars in thousands)

Note 8. Plant, Equipment, Mine Development Costs and Owned and Leased Mineral Rights

Plant, equipment, mine development costs and owned and leased mineral rights consisted of the following at:

	December 31,	
	2008	2007
Owned and leased mineral rights		
Owned and leased mineral rights	$1,291,326	$1,255,218
Less accumulated depletion	(402,812)	(326,779)
	$ 888,514	$ 928,439
Plant, equipment and mine development costs		
Plant, equipment and asset retirement costs	$1,030,016	$ 921,446
Mine development costs	70,922	48,693
Internal use software	38,082	35,838
Coalbed methane equipment and development costs	23,520	11,684
	1,162,540	1,017,661
Less accumulated depreciation and amortization:		
Plant, equipment and asset retirement costs	(448,819)	(332,492)
Mine development costs	(8,179)	(7,144)
Internal use software	(14,164)	(11,347)
Coalbed methane equipment and development costs	(5,769)	(2,249)
	(476,931)	(353,232)
	$ 685,609	$ 664,429

Note 9. Other Noncurrent Assets

Other noncurrent assets consisted of the following at:

	December 31,	
	2008	2007
Receivables from asset dispositions	$ 67	$ 943
Unamortized deferred financing costs, net	8,188	10,022
Advance mining royalties	1,848	1,615
Equity-method investments	9,232	-
Deferred income taxes, net[1]	16,307	-
Other	1,948	1,571
	$ 37,590	$ 14,151

[1] See Note 19

During the three months ended March 31, 2008, the Company acquired a 49% interest in the common stock of Target Drilling Inc. ("Target"), a privately-held contract drilling company for $9,246. The Company has the ability to exercise significant influence over, but not control the operating activities of Target and accordingly uses the equity method of accounting in accordance with Accounting Principles Board Opinion No. 18, *The*

(Dollars in thousands)

Equity Method of Accounting for Investments in Common Stock ("APB 18"). The Company records its proportionate share of earnings or losses of Target in its Consolidated Statements of Operations and Comprehensive (Loss) Income under the caption *Equity in losses of affiliates*. The Company adjusts the carrying amount of its investment in Target for its share of earnings or losses of Target accordingly.

The Company performed a fair value analysis of the net tangible and intangible assets of Target in order to account for the difference in the cost of its investment and its underlying equity in the net assets that were reflected on the books of Target on the date of acquisition. The Company assigned its proportionate share of the difference between the historical cost of the identifiable tangible and intangible assets recorded on the books of Target and their respective fair values based on the fair value analysis. The differences assigned to the identifiable tangible and intangible assets, other than equity-method goodwill, are being amortized over their respective useful lives as a component of *Equity in losses of affiliates*. The differences assigned consisted of tangible assets of $2,315, intangible assets of $1,955 (excluding equity-method goodwill), equity-method goodwill of $3,826 and a deferred tax liability of $1,779.

Note 10. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consisted of the following at:

	December 31,	
	2008	2007
Wages and employee benefits	$ 40,850	$ 37,503
Postretirement benefits other than pension	24,429	23,304
Interest	9,011	9,011
Royalties	7,635	5,492
Taxes, other than income taxes	39,256	38,107
Asset retirement obligations[1]	5,595	4,649
Workers' compensation	8,930	10,450
Accrued capital expenditures	18,893	11,641
Accrued derivatives	28,877	44
Other	19,276	20,790
	$ 202,752	$ 160,991

(1) See Note 18

The December 31, 2008 accrued derivatives balance consists of $24,978 related to swap agreements, of which $23,828 relates to swap agreements that qualify as cash flow hedges in accordance with SFAS No. 133 and $3,899 representing net unrealized losses related to certain forward coal contracts as further described in Note 16.

(Dollars in thousands)

Note 11. Long-Term Debt

Long-term debt consisted of the following at:

	December 31,	
	2008	2007
Senior Secured Credit Facility	$ 301,500	$ 301,500
7.25% Senior Notes	298,285	298,285
	$ 599,785	$ 599,785

Future minimum payments related to the Company's long-term debt as of December 31, 2008 are as follows:

	Senior Secured Credit Facility	7.25% Senior Notes
2009	$ 16,750	$ -
2010	33,500	-
2011	251,250	-
2012	-	-
2013	-	-
Thereafter	-	298,285
Totals	$ 301,500	$ 298,285

Senior Secured Credit Facility

On July 7, 2006, the Company completed an $835,000 amended and restated Senior Secured Credit Facility (the "credit facility"), consisting of a five-year $335,000 Term Loan A and a five-year $500,000 revolving credit facility. The credit facility, which expires in July 2011, bears interest at an applicable margin, plus the lenders' base rate or LIBOR at the Company's option, and requires the Company to pay a commitment fee to the lenders for the unutilized portion of the commitment under the revolving credit facility based on a quarterly leverage ratio calculation. The revolving credit facility provides for up to $500,000 of borrowings for base rate loans, LIBOR loans or letters of credit up to a maximum of the unutilized portion of the revolver. As of December 31, 2008 and 2007, the Company had $329,130 and $327,377, respectively, of available borrowings under its revolving credit facility after giving effect to $170,870 and $172,623 of letters of credit outstanding. The credit facility replaces a debt facility entered into on July 30, 2004 that consisted of a $470,000 term loan facility and a $350,000 revolving credit facility (the "original facility"). Costs capitalized in connection with the credit facility were $4,457. The Company wrote-off $9,209 of unamortized deferred financing costs related to the prior debt facility, based upon the provisions of EITF Issue No. 96-19, *Debtor's Accounting for a Modification or Exchange of Debt Instruments,* and EITF Issue No. 98-14, *Debtor's Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements*. Remaining debt issuance costs are being amortized over the term of the related indebtedness of five years, using the effective interest method. On December 31, 2007, the Company prepaid scheduled principal repayments of $16,750 and $8,375 due in 2008 and the first two quarters of 2009, respectively, on the outstanding balance of the term loan facility. In conjunction with the prepayment, the Company wrote-off $246 of unamortized deferred financing costs associated with the credit facility. At December 31, 2008, the interest rate on the outstanding principal under the credit facility was approximately 1.71%.

(Dollars in thousands)

The terms of the original facility required the Company to maintain at least 50% of its outstanding debt at a fixed rate. To comply with the terms of the original facility, as further described in Note 16, on September 30, 2004, the Company entered into several 3-year interest rate swap agreements all with identical terms, in which it paid fixed interest and received variable interest on a notional amount of $85,000 of its term loan. Under these swap agreements, the Company received a variable rate of 3-month US dollar LIBOR and paid a fixed rate of 3.26%. Settlement of interest payments occurred quarterly. In connection with the closing of the credit facility, the Company terminated the interest rate swaps, as further described in Note 16.

The terms of the Company's credit facility contain financial and other covenants that limit the ability of the Company to, among other things, effect acquisitions or dispositions and borrow additional funds and require the Company to, among other things, maintain various financial ratios and comply with various other financial covenants, including maximum total leverage ratio, minimum interest coverage ratio and a maximum capital expenditures limitation. 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 was in compliance with all covenants at December 31, 2008 and 2007.

7.25% Senior Notes

On July 30, 2004, the Company completed an offering of $300,000 of 7.25% Senior Notes due 2014 in a private placement transaction not subject to the registration requirements under the Securities Act of 1933. In December 2004, $300,000 of 7.25% Notes with identical terms were registered under the Securities Act of 1933 and all of the previously issued Notes were exchanged for these registered Notes. The Notes are guaranteed on a senior unsecured basis, by FCC, and rank equally with all of the Company's other senior unsecured indebtedness. Interest on the Notes is payable on February 1st and August 1st of each year, beginning on February 1, 2005. The terms of the Notes contain restrictive covenants that limit the Company's ability to, among other things, incur additional debt, pay dividends, sell or transfer assets, and make certain investments. The Notes are redeemable, at the Company's option after August 1, 2009 at a redemption price equal to 100% of the principal amount plus an applicable premium. On November 26, 2007, the Company repurchased Notes with a face value of $1,715 and wrote off $41 of unamortized deferred financing costs.

Note 12. Other Noncurrent Liabilities

Other noncurrent liabilities consisted of the following at:

	December 31,	
	2008	2007
Postemployment benefits[2]	$ 4,931	$ 5,090
Pension benefits[2]	115,990	28,564
Workers' compensation	23,396	24,268
Black lung reserves[2]	20,806	12,377
Contract settlement accrual	4,555	10,272
Asset retirement obligations[1]	165,779	149,414
Deferred production tax	11,393	11,002
Deferred credits and other	4,331	8,493
	$ 351,181	$ 249,480

(1) See Note 18
(2) See Note 13

(Dollars in thousands)

Note 13. Employee Benefit Plans

As disclosed in Note 2, the Company adopted the recognition and disclosure provisions of SFAS No. 158 on December 31, 2006. In addition, the Company adopted the measurement date provisions of SFAS No. 158, effective December 31, 2007. Accordingly, the Company uses a December 31 measurement date for its pension and postretirement plan obligations. Prior to 2007, the Company used a September 30 measurement date for its pension and postretirement plan obligations. The adoption of the measurement date provisions of SFAS No. 158 did not have a material effect on the consolidated financial statements.

The following table summarizes the effects of the adoption of the SFAS No. 158 recognition provisions on the Consolidated Balance Sheet at December 31, 2006:

	Prior to the Adoption of SFAS No. 158	Effect of the Adoption of SFAS No. 158	After the Adoption of SFAS No. 158
Postretirement benefits	$ 486,520	$ 50,108	$ 536,628
Other noncurrent liabilities	$ 246,100	$ 6,320	$ 252,420
Deferred income taxes (long-term)	$ 30,416	$ (22,143)	$ 8,273
Accumulated other comprehensive income (loss), net of tax	$ 873	$ (34,285)	$ (33,412)

Actuarial liabilities related to the Company's defined benefit pension and postretirement plans were re-measured in the quarter ended June 30, 2007 in connection with the curtailment event which occurred with respect to the idling of the Wabash mine, as further discussed in Note 3. The curtailment gains of $5,703 were recorded in *Other comprehensive (loss) income* because the curtailment gains did not exceed the unrecognized net losses recorded in *Accumulated other comprehensive (loss) income* related to these plans.

Retirement Plans

The Company and certain of its subsidiaries sponsor two defined benefit pension plans which cover many of the salaried and nonunion represented hourly employees. The Company also sponsors a non-qualified Supplemental Executive Retirement Plan. Benefits are based on either the employee's compensation prior to retirement or stated amounts for each year of service with the Company.

Annual funding contributions to the plans are made as recommended by consulting actuaries based upon the ERISA funding standards. Plan assets consist of equity and fixed income funds, real estate funds, private equity funds and alternative investment funds.

The following table provides components of net periodic benefit cost for the indicated fiscal periods:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Service cost	$ 6,794	$ 6,499	$ 6,257
Interest cost	13,458	12,167	11,094
Expected return on plan assets	(13,263)	(12,212)	(10,570)
Amortization of:			
Prior service credit	(9)	(9)	(9)
Actuarial loss	555	540	405
Net expense	$ 7,535	$ 6,985	$ 7,177

(Dollars in thousands)

Other changes in plan assets and benefit obligations recognized in other comprehensive (loss) income are as follows:

	Twelve Months Ended December 31, 2008
Current year actuarial loss	$ 90,020
Current year prior service cost	1,734
Amortization of:	
Actuarial loss	(555)
Prior service credit	9
Total recognized in other comprehensive income	$ 91,208
Total recognized in net periodic benefit cost and other comprehensive (loss) income	$ 98,743

The estimated amount that will be amortized from accumulated other comprehensive (loss) income into net period benefit cost in 2009 is as follows:

Actuarial loss	$ 6,807
Prior service cost	174
Total	$ 6,981

(Dollars in thousands)

The following tables set forth the plans' benefit obligations, fair value of plan assets and funded status for the indicated fiscal periods:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Change in benefit obligation:		
Benefit obligation at beginning of period	$ 196,926	$ 193,946 [1]
Adjustment for change in measurement date[2]	-	(557)
Service cost	6,794	6,499
Interest cost	13,458	12,167
Actuarial loss	27,343	105
Benefits paid	(11,691)	(13,034)
Plan amendment	1,734	-
Curtailment	-	(2,200)
Benefit obligation at end of period	$ 234,564	$ 196,926
Change in fair value of plan assets:		
Fair value of plan assets at beginning of period	$ 168,362	$ 150,353
Actual return on plan assets	(49,414)	22,078
Employer contributions	11,317	11,316
Benefits paid	(11,691)	(15,385)
Fair value of plan assets at end of period	118,574	168,362
Funded status	(115,990)	(28,564)
Accrued benefit cost at end of year	$ (115,990)	$ (28,564)

[1] Represents the benefit obligation at September 30, 2006.

[2] Represents benefit expenses and benefit payments of $1,794 and ($2,351), respectively, from September 30, 2006 to December 31, 2006.

Gross amounts recognized in accumulated other comprehensive (loss) income consisted of the following as of:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Net actuarial loss (gain) as of measurement date	$ 80,105	$ (9,360)
Prior service cost (credit) as of measurement date	1,686	(57)
Total loss (gain) recognized in accumulated other comprehensive (loss) income	$ 81,791	$ (9,417)

(Dollars in thousands)

The following table presents information applicable to plans with accumulated benefit obligations in excess of plan assets as of:

	December 31, 2008	December 31, 2007
Projected benefit obligation	$ 234,564	$ 196,926
Accumulated benefit obligation	$ 209,581	$ 180,316
Fair value of plan assets	$ 118,574	$ 168,362

Under SFAS No. 158, the current portion of the Company's pension liability is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next twelve months exceeds the fair value of plan assets. However, even though the plan may be underfunded, if there are sufficient plan assets to make expected benefit payments to plan participants in the succeeding twelve months, no current liability should be recognized. Accordingly, at December 31, 2008 and 2007, there was $0 for current pension liability reflected in *Accrued expenses and other current liabilities.* The noncurrent portion of the Company's pension liability as reflected in *Other noncurrent liabilities* at December 31, 2008 and 2007 was $115,990 and $28,564, respectively.

The weighted-average actuarial assumptions used in determining the benefit obligations at the end of each year were as follows:

	December 31, 2008	December 31, 2007
Discount rate	6.10%	6.25%
Rate of increase in future compensation	5.00%	4.00%
Measurement date	December 31, 2008	December 31, 2007

The weighted-average actuarial assumptions used to determine net periodic benefit cost for each year were as follows:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Discount rate[1]	6.25%	5.90%	5.60%
Rate of increase in future compensation	4.00%	4.00%	4.00%
Expected long-term return on plan assets	8.00%	8.00%	8.00%
Measurement date[1]	December 31, 2007	September 30, 2006	September 30, 2005

(1) Actuarial liabilities and net periodic benefit cost related to the Company's defined benefit and postretirement health care and life insurance plans were remeasured as of April 1, 2007 in connection with the idling of the Wabash mine, as discussed in Note 3. The discount rate was increased to 6.00% at that time.

The expected long-term return on plan assets is established at the beginning of each year by the Company's Benefits Committee in consultation with the plans' actuaries and outside investment advisor. This rate is determined by taking into consideration the plans' target asset allocation, expected long-term rates of return on each major asset class by reference to long-term historic ranges, inflation assumptions and the expected additional value from active management of the plans' assets. For the determination of net periodic benefit cost in 2009, the Company will utilize an expected long-term return on plan assets of 8.00%.

(Dollars in thousands)

Assets of the two plans are commingled in the Foundation Coal Defined Benefit Plans Master Trust ("Master Trust") and are invested in accordance with investment guidelines that have been established by the Company's Benefits Committee in consultation with the Master Trust's outside investment advisor. The plans' target allocation for 2009 and the actual asset allocation as reported at December 31, 2008 and 2007 are as follows:

	Target Allocation Percentages 2009	Percentage of Plan Assets 2008	Percentage of Plan Assets 2007
Equity funds	57.0	56.7	57.1
Fixed income funds	28.0	28.2	23.3
Alternative investment funds/private equity funds	9.0	6.5	8.7
Real estate funds	6.0	8.6	10.9
Total	100.0%	100.0%	100.0%

The asset allocation targets have been set with the expectation that the plans' assets will fund the plans' expected liabilities within an appropriate level of risk. In determining the appropriate target asset allocations the Benefits Committee has relied in part upon an Asset/Liability Study performed by the Master Trust's outside investment advisor. This study considers the demographics of the plans' participants, the funding status of each plan, the Company's contribution philosophy, the Company's business and financial profile and other associated risk factors. The plans' assets are periodically rebalanced among the major asset categories to maintain the asset allocation within a range of approximately plus or minus 2% of the target allocation.

For the twelve months ended December 31, 2008 and 2007, $11,317 and $11,316, respectively, of cash contributions were made to the defined benefit retirement plans. The Company expects to contribute approximately $30,000 to the defined benefit retirement plans in 2009.

All of our hourly employees in Pennsylvania represented by the UMWA are covered under multi-employer defined benefit pension plans administered by the UMWA. Company contributions to these multi-employer plans and other contractual payments under the UMWA wage agreement, which are expensed when paid, are based primarily on hours worked and amounted to $14,122, $9,549 and $1,394, for the twelve months ended December 31, 2008, 2007 and 2006, respectively.

The Company and certain of its subsidiaries maintain several defined contribution and profit sharing plans that cover a portion of its employees. Generally, under the terms of the plans, employees make voluntary contributions through payroll deductions and the Company makes matching and/or discretionary contributions, as defined by each plan. The Company's expense related to these plans was $7,054, $6,486 and $5,730, for the twelve months ended December 31, 2008, 2007 and 2006, respectively.

Postretirement Health Care and Life Insurance Benefits

The Company sponsors plans that provide postretirement medical and life insurance benefits to many of our employees. The medical plans provide benefits for most employees who reach normal, or in certain cases, early retirement age while employed by the Company. The postretirement medical plans for salaried and nonunion represented hourly employees are contributory, with annual adjustments to retiree contributions and contain other cost-sharing features such as deductibles and coinsurance. The postretirement medical plan covering union employees is established by collective bargaining and is noncontributory.

(Dollars in thousands)

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the "MMA") was enacted in the United States. The MMA introduces a prescription drug benefit under Medicare Part D as well as a federal subsidy to sponsors of postretirement medical benefit plans such as the Company's plan as long as the provided benefits are actuarially equivalent to Medicare Part D. In accounting for the impact of the MMA, the Company follows FSP No. FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003*. The MMA reduced the Company's net periodic postretirement medical and life insurance benefit cost for the twelve months ended December 31, 2008 and 2007 by approximately $4,960 and $4,588, respectively.

The Centers for Medicare and Medicaid Services ("CMS") issued final regulations related to MMA on January 21, 2005. The Company has elected to continue to provide primary prescription drug benefits to Medicare eligible participants and to apply for federal subsidy payments under the MMA beginning January 1, 2006. Federal subsidies received in 2008 and 2007 were $1,755 and $1,789, respectively.

The following table provides components of net periodic benefit cost for the indicated fiscal periods:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Service cost	$ 7,886	$ 7,805	$ 9,065
Interest cost	31,864	30,680	30,112
Amortization of actuarial loss	-	-	121
Total	$ 39,750	$ 38,485	$ 39,298

Other changes in plan assets and benefit obligations recognized in other comprehensive (loss) income are as follows:

	Twelve Months Ended December 31, 2008
Current year actuarial loss	$ 8,897
Total recognized in other comprehensive (loss) income	$ 8,897
Total recognized in net period benefit cost and other comprehensive (loss) income	$ 48,647

No amounts are estimated to be amortized from accumulated other comprehensive (loss) income into net periodic benefit cost in 2009.

(Dollars in thousands)

The following tables set forth the plans' benefit obligations, fair value of plan assets and funded status for the indicated fiscal periods:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Change in benefit obligation:		
Net benefit obligation at beginning of period	$ 529,091	$ 552,663 [1]
Adjustment for change in measurement date[2]	-	5,385
Service cost	7,886	7,805
Interest cost	31,864	30,680
Actuarial loss (gain)	8,897	(44,166)
Benefits paid	(21,898)	(21,562)
Less: Federal subsidy on benefits paid	1,755	1,789
Curtailment	-	(3,503)
Net benefit obligation at end of period	$ 557,595	$ 529,091
Change in fair value of plan assets:		
Fair value of plan assets at beginning of period	$ -	$ -
Employer contributions	21,898	26,002
Benefits paid	(21,898)	(26,002)
Fair value of plan assets at end of period	-	-
Funded status	(557,595)	(529,091)
Accrued benefit cost at end of year	(557,595)	(529,091)
Less: current portion	24,429	23,304
Noncurrent obligation	$ (533,166)	$ (505,787)

(1) Represents the benefit obligation at September 30, 2006.
(2) Represents benefit expenses and employer contributions of $9,825 and ($4,440), respectively, from September 30, 2006 to December 31, 2006.

Gross amounts recognized in accumulated other comprehensive (loss) income consisted of the following as of:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Net actuarial loss as of measurement date	$ 10,015	$ 1,118

(Dollars in thousands)

The weighted-average assumptions used to determine the benefit obligation as of the end of each year were as follows:

	December 31, 2008	December 31, 2007
Discount rate	6.10%	6.25%
Rate of increase in future compensation	5.00%	4.00%
Measurement date	December 31, 2008	December 31, 2007

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

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Discount rate[1]	6.25%	5.90%	5.60%
Rate of increase in future compensation	4.00%	4.00%	4.00%
Expected long-term return on plan assets	N/A	N/A	N/A
Measurement date[1]	December 31, 2007	September 30, 2006	September 30, 2005

(1) Actuarial liabilities and net periodic benefit cost related to the Company's defined benefit and postretirement health care and life insurance plans were remeasured as of April 1, 2007 in connection with the idling of the Wabash mine, as discussed in Note 3. The discount rate was increased to 6.00% at that time.

The following presents information about the weighted-average annual rate of increase in the per capita cost of covered benefits (i.e., health care cost trend rate):

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Health care cost trend rate assumed for the next year	8.00%	8.00%	9.00%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2014	2013	2010

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effects as of and for the year ended December 31, 2008:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total service and interest cost components	$ 6,496	$ (5,204)
Effect on postretirement benefit obligation	$ 76,827	$ (63,236)

The Company's postretirement medical and life insurance plans are unfunded. For the twelve months ended December 31, 2008, 2007 and 2006, the Company paid $20,143, $19,773 and $19,240, respectively, in postretirement medical and life insurance benefits, net of federal subsidies received under the MMA. The Company expects to contribute approximately $26,000 to its postretirement medical and life insurance plans in 2009.

(Dollars in thousands)

The following represents expected future benefit payments for the next ten years, which reflect expected future service, as appropriate, and the expected federal subsidy related to MMA:

	Pension Benefits	Other Postretirement Benefits	Expected Federal Subsidy
2009	$ 11,983	$ 26,092	$ 1,662
2010	11,076	28,716	1,851
2011	15,227	30,998	2,056
2012	16,498	33,229	2,331
2013	17,489	35,800	2,581
2014-2018	118,687	218,886	17,987
	$190,960	$ 373,721	$ 28,468

The Coal Industry Retiree Health Benefit Act of 1992 ("Coal Act") provides for the funding of medical and death benefits for certain retired members of the UMWA through premiums to be paid by assigned operators (former employers). The Company treats its obligations under the Coal Act as participation in a multi-employer plan and recognizes the expense as premiums are paid. Expense relative to premiums paid for the twelve months ended December 31, 2008, 2007 and 2006 was $1,848, $2,759 and $2,519, respectively. As required under the Coal Act, the Company's obligation to pay retiree medical benefits to its UMWA retirees is secured by letters of credit in the amount of $8,113 as of December 31, 2008.

Other Employee Benefit Plans

The Company has a number of postemployment plans covering severance, disability income and continuation of health care and life insurance benefits for disabled employees. At December 31, 2008 and 2007, the discounted accumulated postemployment benefit liability for these plans consisted of a current amount of $1,017 and $1,106, respectively, included in *Accrued expenses and other current liabilities* (wages and employee benefits) and a noncurrent amount of $3,861 and $3,891, respectively, included in *Other noncurrent liabilities*.

The Company provides health care coverage for all of its employees under a number of plans. The Company is self-insured for the cost of these benefits. During the twelve months ended December 31, 2008, 2007 and 2006, total claims expense of $46,022, $37,743 and $36,798, respectively, was incurred, which represents the claims processed and an estimate for claims incurred but not reported.

Pneumoconiosis Expense and Trust

The Company is self-insured with respect to black lung medical and disability benefits to its employees and their dependants under the Federal Coal Mine Health and Safety Act of 1969, as amended, and various state workers' compensation statutes. The Company pays black lung benefits through the tax-exempt Foundation Coal Black Lung Benefits Trust (the "Trust"). Assets of the Trust are invested solely in United States Treasury Notes.

(Dollars in thousands)

The present value of accumulated black lung obligations is calculated annually by an independent actuary. This calculation is based on assumptions regarding disability incidence, medical costs, mortality, death benefits, dependents and interest rates. These assumptions are derived from Company experience and credible outside sources.

Black lung expense is calculated using the service cost methodology of SFAS No. 106. Actuarial gains and losses and prior service costs are amortized over the remaining service lives of the active miners. The discount rate used to calculate the present value of accumulated benefits at December 31, 2008 is 6.10%. The assumed annual investment rate of return on the Trust assets is 4.50%. The rate of compensation is assumed to increase at an annual rate of 3.50%.

The following tables set forth the accumulated black lung benefit obligations, fair value of plan assets and funded status for the indicated fiscal periods:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Change in benefit obligation:		
Benefit obligation at beginning of period	$ 22,843	$ 23,033 [1]
Adjustment for change in measurement date[2]	-	60
Service cost	1,084	696
Interest cost	1,745	1,361
Actuarial loss (gain)	5,850	(385)
Benefits paid	(3,195)	(1,922)
Benefit obligation at end of period	$ 28,327	$ 22,843
Change in fair value of plan assets:		
Fair value of plan assets at beginning of period	$ 10,466	$ 12,139
Actual return on plan assets	250	600
Benefits and other payments	(3,195)	(2,273)
Fair value of plan assets at end of period	7,521	10,466
Funded status	(20,806)	(12,377)
Accrued benefit cost at end of year	$ (20,806)	$ (12,377)

(1) Represents the benefit obligation at September 30, 2006.
(2) Represents benefit expenses and benefit payments of $411 and ($351), respectively, from September 30, 2006 to December 31, 2006.

Gross amounts recognized in accumulated other comprehensive (loss) income consisted of the following as of:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Net actuarial loss as of measurement date	$ 8,207	$ 2,805

(Dollars in thousands)

The following table provides components of net periodic benefit cost for the indicated fiscal periods:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Service cost	$ 1,084	$ 696	$ 706
Interest cost	1,745	1,361	1,314
Expected return on plan assets	(430)	(499)	(575)
Amortization of actuarial loss	629	115	198
Net periodic expense	$ 3,028	$ 1,673	$ 1,643

Other changes in plan assets and benefit obligations recognized in other comprehensive (loss) income are as follows:

	Twelve Months Ended December 31, 2008
Current year actuarial loss	$ 6,030
Amortization of actuarial loss	(629)
Total recognized in other comprehensive (loss) income	$ 5,401
Total recognized in net periodic benefit cost and other comprehensive (loss) income	$ 8,429

The estimated amount that will be amortized from accumulated other comprehensive (loss) income into net periodic benefit cost in 2009 is as follows:

Actuarial loss	$ 629
Total	$ 629

Note 14. Workers' Compensation Benefits

The Company is largely self-insured for workers' compensation claims. The liability for workers' compensation claims is an actuarially determined estimate of the undiscounted ultimate losses to be incurred on such claims based on the Company's experience, and includes a provision for incurred but not reported losses. Adjustments to the probable ultimate liability are made semi-annually based on subsequent developments and experience and are included in operations as they are determined. These obligations are secured by letters of credit in the amount of $39,124 and surety bonds in the amount of $7,104.

The liability for self-insured workers' compensation benefits at December 31, 2008 and 2007 was $32,326 and $34,718, respectively, including a current portion of $8,930 and $10,450, respectively, which is included in *Accrued expenses and other current liabilities*. Workers' compensation expense for the twelve months ended December 31, 2008, 2007 and 2006, was $7,706, $15,156 and $13,259, respectively, and is included in *Cost of coal sales* in the Consolidated Statements of Operations and Comprehensive (Loss) Income.

Note 15. Stock-Based Compensation

On July 30, 2004, the Company's Board adopted the Foundation Coal Holdings, Inc. 2004 Stock Incentive Plan (the "Plan"), which is designed to assist the Company in recruiting and retaining key employees, directors and consultants. The Plan, which was amended and restated, and was effective on May 22, 2008 upon shareholder approval, permits the Company to grant its key employees, directors and consultants non-qualified stock options ("options"), stock appreciation rights, restricted stock or other stock-based awards. The shares under the Plan may be issued at an exercise price of no less than 100% of the fair market value of the Company's common stock on the date of grant. The Plan is currently authorized for the issuance of awards for up to 5,978,483 shares of common stock. At December 31, 2008, 2,113,763 shares of common stock were available for grant under the Plan.

Prior to January 1, 2006, the Company accounted for its stock-based compensation plans under the recognition and measurement provisions of APB No. 25, and related interpretations, as permitted by SFAS No. 123. Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123(R), using the modified prospective transition method.

The Company has three types of stock-based awards: restricted stock units, restricted stock and options. Total compensation expense related to stock-based awards recognized in *Selling, general and administrative expenses* for the twelve months ended December 31, 2008 was $10,500, consisting of $6,490, $574 and $3,436 for restricted stock units, restricted stock and options, respectively. Total compensation expense related to stock-based awards recognized in *Cost of coal sales* for the twelve months ended December 31, 2008 was $3,117 for restricted stock units. Compensation expense related to stock-based awards recognized in *Selling, general and administrative expenses* for the twelve months ended December 31, 2007 was $5,095, consisting of $3,255, $392 and $1,448 for restricted stock units, restricted stock and options, respectively. Compensation expense related to stock-based awards recognized in *Cost of coal sales* for the twelve months ended December 31, 2007 was $1,475 for restricted stock units. Compensation expense related to stock-based awards recognized in *Selling, general and administrative expenses* for the twelve months ended December 31, 2006 was $2,678 consisting of $1,030, $281 and $1,367 for restricted stock units, restricted stock and options, respectively. Compensation expense related to stock-based awards recognized in *Cost of coal sales* for the twelve months ended December 31, 2006 was $368 for restricted stock units. During the first quarter of 2008, the Company modified the vesting conditions for certain stock options and modified the performance criteria for certain restricted stock units. Approximately 100 employees were affected by the modifications to stock options and restricted stock units. The Company remeasured the affected stock-based awards in accordance with SFAS No. 123(R) and recognized additional compensation expense of approximately $2,738 and $525 in *Selling, general and administrative expenses* and *Cost of coal sales,* respectively, for the twelve months ended December 31, 2008.

The excess tax benefit from stock-based awards was $5,308, $3,292 and $9,476 during the twelve months ended December 31, 2008, 2007 and 2006, respectively.

Below is a summary of the key terms and methods of valuation for the Company's stock-based compensation awards.

Restricted Stock Units

During the twelve months ended December 31, 2006, the Company granted 248,884 performance units and 35,840 time units to certain key employees. These performance units are earned each December 31, contingent upon the achievement of certain annual performance targets. Generally, performance targets related to specific tranches of these performance units are established prior to each annual reporting cycle. The performance units earned in each annual performance cycle cliff vest subject to continued employment with the Company through the vesting dates, which occur through 2010, at which time shares of common stock equal to the number of performance units earned will be distributed. The time units vest over various periods through June 30, 2009. The weighted-average grant-date fair value of restricted stock units granted in 2006 for which the measurement date had occurred was $43.67 per unit.

(Dollars in thousands)

During the twelve months ended December 31, 2007, the Company granted 27,710 performance units and 36,770 time units to certain key employees. These performance units are earned each December 31, contingent upon the achievement of certain annual performance targets. Performance targets related to specific tranches of these performance units are established in the restricted stock unit agreement for grants to members of senior management or prior to each annual reporting cycle for grants to members of management. The performance units earned cliff vest subject to continued employment with the Company through the vesting dates, which occur through 2010, at which time shares of common stock equal to the number of performance units earned will be distributed. The time units vest over various periods through 2010. The weighted-average grant-date fair value of restricted stock units granted in 2007 for which the measurement date had occurred was $38.89 per unit. The fair value of restricted stock units that vested during the twelve months ended December 31, 2007 was $297.

During the twelve months ended December 31, 2008, the Company granted 57,456 performance units and 63,257 time units to certain key employees. These performance units are earned each December 31, contingent upon the achievement of certain annual performance targets. Performance targets related to specific tranches of these performance units are established in the restricted stock unit agreement for grants to members of senior management or prior to each annual reporting cycle for grants to members of management. The performance units earned cliff vest subject to continued employment with the Company through the vesting date, which occur through 2011, at which time shares of common stock equal to the number of performance units earned will be distributed. The time units vest over various periods through 2011. The fair value of restricted stock units that vested during the twelve months ended December 31, 2008 was $6,010.

The following is a summary of the Company's restricted stock unit activity during the twelve months ended December 31, 2008:

	Number of Shares	Weighted-Average Grant-Date Fair Value[1]
Restricted stock units outstanding at December 31, 2007	460,632	$ 38.39
Granted	120,713	$ 45.46
Vested	(112,718)	$ 29.02
Forfeited	(30,718)	$ 49.07
Restricted stock units outstanding at December 31, 2008	437,909	$ 39.18

(1) The weighted-average grant-date fair value reflects the value of restricted stock units for which the measurement date has occurred.

The measurement date for each tranche of performance units is the date on which the annual performance targets are approved relating to such tranche (the "measurement date"). Compensation cost for each tranche is measured based upon the closing market price of the Company's common stock at the measurement date. There are no market or performance conditions that could cause an employee to forfeit an award prior to the measurement date for each specific tranche. At December 31, 2008, the measurement date had not occurred for 19,152 performance units. Compensation expense is recognized ratably from the measurement date of each tranche through the vesting date at which time the number of shares of common stock which have been earned will be distributed.

(Dollars in thousands)

Unrecognized compensation expense for time and performance units for which the measurement date has occurred is $3,946. These costs are expected to be recognized over a weighted-average period of 1.2 years. The amount of compensation expense related to performance units that will be recognized in future periods is determined by the achievement of performance targets.

Restricted Stock

The Company granted 15,000 shares of restricted stock to certain members of the Board of Directors during the twelve months ended December 31, 2006. The shares are subject to the member's continuous service as a director of the Company, with the restriction lapsing ratably each December 31, over various vesting periods through December 31, 2010. The weighted-average grant-date fair value of the restricted stock granted during the twelve months ended December 31, 2006 was $40.26 per share. The fair value of restricted stock shares that vested on December 31, 2006 was $244.

The Company granted 10,500 shares of restricted stock to certain members of the Board of Directors during the twelve months ended December 31, 2007. The shares are subject to the member's continuous service as a director of the Company, with the restriction lapsing ratably each December 31, through December 31, 2009. The weighted-average grant-date fair value of the restricted stock granted during the twelve months ended December 31, 2007 was $31.67 per share. The fair value of restricted stock shares that vested on December 31, 2007 was $584.

The Company granted 10,500 shares of restricted stock to certain members of the Board of Directors during the twelve months ended December 31, 2008. The shares are subject to the member's continuous service as a director of the Company, with the restriction lapsing ratably each December 31, through December 31, 2010. The fair value of restricted stock shares that vested on December 31, 2008 was $200.

The following is a summary of the Company's restricted stock activity during the twelve months ended December 31, 2008:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Restricted stock outstanding at December 31, 2007	20,100	$ 35.42
Granted	10,500	$ 52.12
Vested	(14,700)	$ 13.62
Forfeited	-	$ -
Restricted stock outstanding at December 31, 2008	15,900	$ 43.06

Total unrecognized compensation expense related to restricted stock grants is $685 as of December 31, 2008, which is expected to be recognized over a weighted-average period of 1.1 years.

(Dollars in thousands)

Non-qualified Stock Options

On August 10, 2004, options to acquire 3,536,432 shares of common stock were issued to eight members of senior management of the Company. No options were granted during 2008, 2007 or 2006. Of the total options granted, there were 982,343 options granted at an exercise price of $4.87 per share, which are subject to continued employment, vest and become exercisable on each December 31 beginning December 31, 2004 and ending on December 31, 2008. Additionally, there were 2,554,089 options granted at an exercise price of $8.53 per share, which are subject to continued employment, vest and become exercisable on the eighth anniversary of the date of grant and provide for partial accelerated vesting each calendar year through December 31, 2008 upon achievement of certain annual performance targets. During 2008, 2007 and 2006, 415,039, 415,039 and 383,113, respectively, of the options granted at the $8.53 per-share exercise price vested on an accelerated basis as a result of achieving certain performance targets.

The fair market value of option grants was estimated on the date of the grant using the Black-Scholes option-pricing model using the following assumptions:

Risk-free interest rates	3.94%
Dividends yield	0.70%
Expected volatility	55.00%
Expected life in years	8.00

As the Company lacked a sufficient trading history at the date the fair value of options was estimated in 2004, the Company's volatility was based on the volatility of other companies in the mining industry. The weighted-average grant-date fair value of the options was $2.45.

The following is a summary of all option activity during the twelve months ended December 31, 2008:

	Number of Shares	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Options outstanding at December 31, 2007	1,543,274	$ 7.69	
Granted	-	$ -	
Exercised	(511,405)	$ 7.29	
Forfeited	-	$ -	
Options outstanding at December 31, 2008	1,031,869	$ 7.89	$ 6,325
Exercisable at December 31, 2008	928,112	$ 7.82	$ 5,754
Expected to vest as of December 31, 2008	90,790	$ 8.53	$ 498

The total intrinsic value, the difference between the exercise price and the market price on the date of exercise, of all options exercised during the twelve months ended December 31, 2008, 2007 and 2006 was $26,778, $20,412 and $34,183, respectively.

During 2008, 574,670 options vested. The weighted-average grant-date fair value of options vested during 2008 was $2.45.

(Dollars in thousands)

A summary of the Company's options outstanding at December 31, 2008 follows:

	Options Outstanding			Options Exercisable	
Exercise Price	Shares	Weighted-Average Remaining Life (yrs)	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
$ 4.87	181,234	5.61	$ 4.87	181,234	$ 4.87
$ 8.53	850,635	5.61	$ 8.53	746,878	$ 8.53

Total unrecognized compensation expense from options was $208 as of December 31, 2008, which is expected to be recognized over an average period of 3.7 years.

Note 16. Derivative Instruments and Hedging Activities

Cash Flow Hedges

The Company is subject to the risk of price volatility for certain of the materials and supplies used in production, such as diesel fuel and explosives. As a part of its risk management strategy, the Company enters into swap agreements with financial institutions to mitigate the risk of price volatility for both diesel fuel and explosives. The Company has designated certain swap agreements as qualifying cash flow hedges in accordance with SFAS No. 133. As of December 31, 2008, the Company had swap agreements outstanding to hedge the variable cash flows related to 13,062,000 gallons of anticipated diesel fuel usage for calendar year 2009. As of December 31, 2008, the Company had swap agreements outstanding to hedge the variable cash flows related to approximately 38,000 tons and 8,300 tons of anticipated explosive usage for calendar years 2009 and 2010, respectively. As of December 31, 2008, a liability of $23,828 related to these cash flow hedges is included in *Accrued expenses and other current liabilities* (see Note 10). Unrealized losses recorded in *Accumulated other comprehensive (loss) income* were $15,281, net of income tax benefit of $4,149. The Company recorded unrealized losses of $4,050 in the Consolidated Statements of Operations and Comprehensive (Loss) Income for the twelve months ended December 31, 2008 under the caption *Net change in fair value of derivative instruments* for certain diesel fuel related swaps that represented mark-to-market losses prior to the swaps being designated as qualifying cash flow hedges. Amounts recorded for the ineffective portion of diesel fuel and explosive hedges in the Consolidated Statements of Operations and Comprehensive (Loss) Income for the twelve months ended December 31, 2008 were $348.

Unrealized losses recorded in *Accumulated other comprehensive (loss) income* are reclassified to income or loss as the financial swaps settle and the Company purchases the underlying diesel fuel and explosives that are being hedged. During the next twelve months, the Company expects to reclassify approximately $13,997, net of tax, for diesel fuel hedges and approximately $1,253, net of tax, for explosive hedges.

On September 30, 2004, the Company entered into pay-fixed, receive-variable interest rate swap agreements on a notional amount of $85,000 that was designated as a qualifying cash flow hedge. In connection with the July 7, 2006 closing of the Company's Senior Secured Credit Facility, the Company terminated the swap agreements. Subsequently, the Company monetized the $2,371 derivative asset included in *Other noncurrent assets* in the Company's consolidated financial statements at June 30, 2006 and recognized a $112 mark-to-market loss on the swaps. The $1,841 unrealized gain from the change in the market value of the interest rate swaps recorded in *Accumulated other comprehensive (loss) income* was being recognized into income on a prorated basis over the remaining term of the original interest rate swap agreement through September 28, 2007.

(Dollars in thousands)

At December 31, 2006, the unamortized unrealized gain was $1,114 which was fully offset against *Interest expense* during the twelve months ended December 31, 2007.

The following table summarizes the changes to *Accumulated other comprehensive (loss) income* related to hedging activities during the twelve months ended December 31, 2008:

Balance December 31, 2007	Net Amounts Reclassified to Earnings	Net Change Associated With Current Period Hedging Transactions	Balance December 31, 2008
$ (26)	$ (351)	$ (14,904)	$ (15,281)

Forward Contracts

The Company evaluates each of its coal sales and coal purchase forward contracts under SFAS No. 133 to determine if they qualify for the normal purchase normal sale ("NPNS") exception prescribed by SFAS No. 133. The majority of our forward contracts do qualify for the NPNS exception based on management's intent and ability to physically deliver or take physical delivery of the coal. Contracts that do not qualify for the NPNS exception are treated as derivatives under SFAS No. 133 and are accounted for at fair value. Those contracts that qualify as derivatives have not been designated as cash flow hedges and accordingly, the Company includes the unrealized gains and losses in current period earnings or losses. The Company has recorded net unrealized losses of $3,899 related to contracts that qualify as derivatives in the Consolidated Statements of Operations and Comprehensive (Loss) Income for the twelve months ended December 31, 2008 under the caption *Net change in fair value of derivative instruments.* A liability of $3,899 is included in *Accrued expenses and other current liabilities* (see Note 10) in the Consolidated Balance Sheets as of December 31, 2008.

Other Derivative Instruments

The Company also has certain other financial swap agreements that have not been designated as cash flow hedges. The swaps were entered into to mitigate the risk of price volatility for diesel fuel in 2010. As of December 31, 2008, a liability of $1,150 related to the fair value of these swaps is included in *Accrued expenses and other current liabilities* (see Note 10) and an equal amount recorded in the Consolidated Statements of Operations and Comprehensive (Loss) Income for the twelve months ending December 31, 2008 under the caption *Net change in fair value of derivative instruments.*

Note 17. Fair Value of Financial Instruments

The estimated fair values of financial instruments under SFAS No. 107, *Disclosures About Fair Value of Financial Instruments,* are determined based on relevant market information. These estimates involve uncertainty and cannot be determined with precision. The following methods and assumptions are used to estimate the fair value of each class of financial instrument.

Trade accounts receivable, trade accounts payable, accrued expenses and other current liabilities: The carrying amounts approximate fair value because of the short maturity of these instruments.

Long-term debt: The fair value of long-term debt is estimated based on a current market rate of interest offered to the Company for debt of similar maturities.

(Dollars in thousands)

The estimated fair values of financial instruments are as follows at:

	December 31,			
	2008		2007	
	Carrying Values	Fair Values	Carrying Values	Fair Values
Long-term debt	$599,785	$551,098	$599,785	$628,323

Note 18. Asset Retirement Obligations

The Company's mining activities are subject to various federal and state laws and regulations governing the protection of the environment. These laws and regulations are continually changing and are generally becoming more restrictive. The Company conducts its operations to protect the public health and environment and believes its operations are in material compliance with all applicable laws and regulations. The Company has made, and expects to make in the future, expenditures to comply with such laws and regulations. Estimated future reclamation costs are based principally on legal and regulatory requirements.

The following table describes all changes to the Company's asset retirement obligations from December 31, 2007 through December 31, 2008:

Asset retirement obligations, December 31, 2007	$ 154,063
Accretion expense	11,429
Revisions in estimated cash flows and liabilities incurred	9,170
Liabilities settled	(3,288)
Asset retirement obligations, December 31, 2008	$ 171,374

The current portions of the asset retirement obligation liabilities of $5,595 and $4,649 at December 31, 2008 and 2007, respectively, are included in *Accrued expenses and other current liabilities*. See Note 10. The noncurrent portion of the Company's asset retirement obligation liabilities of $165,779 and $149,414 at December 31, 2008 and 2007, respectively, are included in *Other noncurrent liabilities*. See Note 12. There were no assets that were legally restricted for purposes of settling asset retirement obligations at December 31, 2008 or 2007. At December 31, 2008, regulatory obligations for asset retirements are secured by surety bonds in the amount of $275,151. These surety bonds are partially collateralized by letters of credit issued by the Company.

Expected future cash payments to settle asset retirement obligations are as follows at December 31, 2008:

Year Ended December 31,	
2009	$ 5,595
2010	7,696
2011	4,693
2012	906
2013	1,722
Thereafter	235,181
Total payments[1]	$ 255,793

[1] The difference between total expected payments of $255,793 and the liability of $171,374 recorded in the Consolidated Balance Sheets represents the application of an inflation rate and a discount rate.

(Dollars in thousands)

Note 19. Income Taxes

Income taxes consisted of the following:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Income tax (expense) benefit	$ (6,646)	$ 8,114	$ (3,831)
Deferred benefit (expense) related to components of other comprehensive income and stockholders' equity	28,686	(23,806)	21,390
Tax benefit of cumulative effect of change in accounting principle	-	-	21,142
	$ 22,040	$ (15,692)	$ 38,701

Income tax (expense) benefit from continuing operations consisted of the following:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Current federal tax expense	$ (11,774)	$ (14,429)	$ (26,064)
Current state tax expense	(1,538)	(1,169)	(3,424)
	(13,312)	(15,598)	(29,488)
Deferred federal tax benefit	9,328	19,377	15,752
Deferred state tax (expense) benefit	(2,662)	4,335	9,905
	6,666	23,712	25,657
Total income tax (expense) benefit	$ (6,646)	$ 8,114	$ (3,831)

The following is a reconciliation between the amount determined by applying the United States federal income tax rate of 35% to income before income taxes and the actual income tax expense:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Federal statutory income tax expense	$ (6,654)	$ (8,573)	$ (12,344)
Other (increase) decrease:			
State income tax (expense) benefit, net of U.S. federal tax benefit	748	3,377	(1,253)
Excess percentage depletion	25,215	17,091	13,373
Change in valuation allowance	(26,358)	(6,440)	(7,624)
Effect of Medicare Prescription Drug, Improvement, and Modernization Act of 2003	1,736	1,606	1,770
Nondeductible expenses and other	(804)	181	1,296
Other permanent differences	(529)	872	951
Total income tax (expense) benefit	$ (6,646)	$ 8,114	$ (3,831)

(Dollars in thousands)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities consisted of the following at:

	December 31, 2008	December 31, 2007
Deferred tax assets:		
Net operating loss carryforwards	$ 13,467	$ 7,559
Alternative minimum tax credit carryforwards	46,880	32,041
Postretirement benefits	247,221	235,586
Pension cost, net	37,623	11,405
Coal supply agreements, net	17,909	20,347
Reclamation and mine closure, net	28,612	21,710
Accrued expenses	10,375	11,223
Derivatives	10,433	-
Equity investment	411	-
Other	30,319	27,779
Total gross deferred tax assets	443,250	367,650
Less valuation allowance	(99,950)	(48,732)
Deferred tax assets, net of valuation allowance	$ 343,300	$ 318,918
Deferred tax liabilities:		
Plant and equipment	$ (42,317)	$ (31,190)
Coal reserves-leased and owned	(248,778)	(267,219)
Prepaid expenses	(6,093)	(7,636)
Other	(503)	(4,676)
Total gross deferred tax liabilities	(297,691)	(310,721)
Net deferred tax asset	$ 45,609	$ 8,197

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent on the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, taxable income available in carryback years, projected future taxable income and tax planning strategies in making this assessment. Based on the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management has established a valuation allowance of $99,950 and $48,732 at December 31, 2008 and December 31, 2007, respectively.

The Company has historically paid tax under the alternative minimum tax (AMT) system for federal purposes. The Company believes that it is more likely than not that the Company will be an AMT taxpayer indefinitely. Thus, the Company has recorded a valuation allowance to reflect the realizability of its federal deferred tax assets under the AMT system. This includes a full valuation allowance on the Company's accumulated AMT credit carryforwards and a valuation allowance for the difference between the federal regular tax rate and AMT rate attributable to the Company's net deferred tax assets. The Company has also recorded a valuation allowance for certain state deferred tax assets, including net operating losses, based upon an assessment of the realizability of those assets. A portion of the Company's valuation allowance has been recorded as a component of other comprehensive (loss) income in accordance with the intraperiod tax allocation provisions of SFAS No. 109.

(Dollars in thousands)

At December 31, 2008, the Company has regular net operating loss carryforwards for Federal income tax purposes of $11,813 which are available to offset future regular Federal taxable income, if any, through 2028. The Company has net operating loss carryforwards for state income tax purposes of $187,193 which are available to offset future state taxable income through 2028. The Company also has alternative minimum tax credit carryforwards of approximately $46,880, which are available to reduce future Federal regular income taxes, if any, over an indefinite period.

As disclosed in Note 2, the Company adopted the provisions of FIN 48 as of January 1, 2007. The cumulative effect of the adoption of FIN 48 was zero. A reconciliation of the beginning and ending amount of total unrecognized tax benefits as of December 31, 2008 is as follows:

	2008	2007
Balance as of January 1	$ 10,108	$ 9,671
Increase related to prior year tax positions	1	393
Increase related to current year tax positions	1,976	44
Settlements	(7,316)	-
Lapse of statute of limitations	(532)	-
Balance as of December 31	$ 4,237	$ 10,108

Included in the balance of total unrecognized tax benefits at December 31, 2008, are potential benefits of $2,991 that if recognized, would affect the effective rate on income from continuing operations.

Management determined it is reasonably possible that certain of these unrecognized tax benefits will decrease during the next twelve months, including the expiration of certain state statutes of limitations. The range of potential unrecognized tax benefits to be released is estimated to be between $900 and $1,414.

The Company conducts business throughout the United States and, as a result, the Company or one or more of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions, including West Virginia and Pennsylvania. The Company also has significant Wyoming operations where there is no state income tax. The Company's U.S. Federal, West Virginia and Pennsylvania statutes of limitations has generally closed for tax years prior to 2005, 2005, and 2003, respectively, except to the extent where there were net operating losses carried forward and utilized in open tax years.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits as a component of tax expense. During the years ended December 31, 2008, 2007 and 2006, the Company recorded an interest (credit) or expense related to unrecognized tax benefits of approximately ($806), $1,089 and $251, respectively. Total accrued interest and penalties as of December 31, 2008 and December 31, 2007 was $534 and $1,340, respectively.

State franchise tax expense for the twelve months ended December 31, 2008, 2007 and 2006 was $1,437, $1,836, and $1,389, respectively. State franchise taxes are included in *Cost of coal sales* in the Consolidated Statements of Operations and Comprehensive (Loss) Income.

Note 20. Stockholders' Equity, Earnings Per Share and Accumulated Other Comprehensive (Loss) Income

Stockholders' Equity

The Company has 100,000,000 authorized shares of $0.01 par value common stock of which approximately 44,555,825 and 44,991,000 shares were outstanding at December 31, 2008 and 2007, respectively. Holders of common stock are entitled to one vote per share on all matters to be voted upon by the stockholders. The holders of common stock do not have cumulative voting rights in the election of directors. Holders of common stock are entitled to ratably receive dividends if and when dividends are declared from time to time by the Board. Upon liquidation, dissolution or winding up, any business combination or a sale or disposition of all or substantially all of the assets of the Company, the holders of common stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and accrued but unpaid dividends and liquidation preferences on any outstanding preferred stock. The common stock has no preemptive or conversion rights and is not subject to further calls or assessment by the Company. There are no redemption or sinking fund provisions applicable to the common stock. Holders of restricted stock shares are entitled to dividends and have voting rights. Holders of restricted stock units are not entitled to dividends and do not have any voting rights.

In addition to the common stock, the Board is authorized to issue up to 10,000,000 of $0.01 par value shares of preferred stock of which there were none issued and outstanding at December 31, 2008 and 2007. The Board is authorized to determine the terms and rights, including the number of authorized shares, whether dividends (if any) will be cumulative or non-cumulative and the dividend rate, redemption or sinking fund provisions, conversion terms, prices and rates, and amounts payable on shares in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Company. The Board may also determine restrictions on the issuance of shares and the voting rights (if any) of the holders.

During the twelve months ended December 31, 2008 and 2007, the Company declared and paid cash dividends of $9,025 and $9,027, respectively.

The credit facility currently limits cash available to pay dividends to $30,000 for any consecutive four-quarter period.

In July 2006, the Board of Directors authorized a stock repurchase program (the "Repurchase Program"), authorizing the Company to repurchase shares of its common stock. The Company may repurchase its common stock from time to time, as determined by authorized officers of the Company. In September 2008, the Board of Directors authorized a $100,000 increase to the Repurchase Program, up to an aggregate amount of $200,000. Repurchases of common shares in a cumulative amount over $100,000 are subject to a maximum leverage ratio test of pro-forma net debt to adjusted EBITDA of less than 2.25 to 1.00 under the credit facility. The ratio test must be met at the time of each applicable share repurchase. During the twelve months ended December 31, 2008, the Company expended $39,263 to repurchase 1,030,145 shares of its common stock at an average price of $38.11 per share under the Repurchase Program. During the twelve months ended December 31, 2007, the Company expended $35,262 to repurchase 1,060,669 shares of its common stock at an average price of $33.24 per share under the Repurchase Program. At December 31, 2008, $113,586 of funds remained under the Repurchase Program. During the twelve months ended December 31, 2008, the Company issued 112,718 shares of common stock to employees upon vesting of restricted stock units. The Company repurchased 39,669 common shares withheld from employees to satisfy the employees' minimum statutory tax withholdings upon vesting.

(Dollars in thousands)

Earnings per Share

The following table provides a reconciliation of weighted-average shares outstanding used in the basic and diluted earnings per share computations for the periods presented:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Weighted-average shares-basic	45,073,432	45,156,659	45,397,370
Dilutive impact of employee stock options	756,246	1,140,393	1,361,371
Dilutive impact of restricted stock plans	231,014	125,901	54,566
Weighted-average shares-diluted	46,060,692	46,422,953	46,813,307

In the twelve months ended December 31, 2008 and 2006, 51,358 and 147,192 restricted stock units, respectively, that could potentially dilute basic earnings per share in the future were not included in the computation of diluted earnings per share because to do so would have been anti-dilutive.

Accumulated Other Comprehensive (Loss) Income

Components of accumulated other comprehensive (loss) income, net of tax, consisted of the following at:

	December 31, 2008	December 31, 2007
Defined benefit pension, postretirement and other Company sponsored plans	$ (78,097)	$ 2,429
Unrealized losses on cash flow hedges	(15,281)	(26)
Total	$ (93,378)	$ 2,403

Note 21. Segment Information

The Company produces primarily steam coal from surface and deep mines for sale to utility and industrial customers, which is distributed by rail, barge and/or truck. The Company operates only in the United States with operating mines in three of the major coal basins. The Company has four reportable business segments: Northern Appalachia, consisting of two underground mines in southwestern Pennsylvania; Central Appalachia, consisting of six underground mines and two surface mines in southern West Virginia; the Powder River Basin, consisting of two surface mines in Wyoming and the Company's Other segment. Other includes an idled underground mine in Illinois; expenses associated with closed mines; Dry Systems Technologies; coal trade activities; selling, general and administrative expenses not charged out to the Powder River Basin, Northern Appalachia or Central Appalachia mines and the elimination of inter-company transactions. The Company evaluates the performance of its segments based on income (loss) from operations.

(Dollars in thousands)

Segment results for the twelve months ended December 31, 2008 were as follows:

	Powder River Basin	Northern Appalachia	Central Appalachia	Other	Consolidated
Total revenues[1]	$ 500,618	$ 650,373	$ 496,589	$ 42,550	1,690,130
Income (loss) from operations	25,560	94,626	22,511	(77,719)	64,978
Equity in earnings (losses) of affiliates	6	(816)	-	-	(810)
Depreciation, depletion and amortization	47,132	91,457	66,382	7,195	212,166
Amortization of coal supply agreements	3,423	(88)	(2,832)	865	1,368
Capital expenditures	19,133	110,783	25,492	1,521	156,929
Acquisition of mineral rights under federal lease	36,108	-	-	-	36,108
Equity-method investments	1,021	8,211	-	-	9,232
Total assets at December 31, 2008	$ 495,332	$ 919,360	$ 394,823	$ 158,593	1,968,108

(1) For the twelve months ended December 31, 2008, total revenues included revenues related to coal shipped to customers outside of the U.S. of $64,944, $553 and $9,624 for the Northern Appalachia, Central Appalachia and Other segments, respectively.

Segment results for the twelve months ended December 31, 2007 were as follows:

	Powder River Basin	Northern Appalachia	Central Appalachia	Other	Consolidated
Total revenues	$ 470,886	$ 533,789	$ 458,271	$ 26,717	$ 1,489,663
Income (loss) from operations	75,376	91,694	(2,982)	(89,460)	74,628
Depreciation, depletion and amortization	44,940	80,087	68,576	8,426	202,029
Amortization of coal supply agreements	4,354	736	(8,588)	84	(3,414)
Capital expenditures	35,649	95,474	26,517	16,754	174,394
Total assets at December 31, 2007	$ 490,343	$ 862,972	$ 427,040	$ 127,809	$ 1,908,164

Segment results for the twelve months ended December 31, 2006 were as follows:

	Powder River Basin	Northern Appalachia	Central Appalachia	Other	Consolidated
Total revenues	$ 420,264	$ 540,873	$ 455,507	$ 53,677	$ 1,470,321
Income (loss) from operations	46,986	143,858	10,584	(104,552)	96,876
Depreciation, depletion and amortization	42,302	73,719	59,501	7,679	183,201
Amortization of coal supply agreements	14,443	(9,122)	(18,807)	364	(13,122)
Capital expenditures	28,361	64,374	48,805	45,677	187,217
Total assets at December 31, 2006	$ 497,956	$ 863,702	$ 469,616	$ 118,306	$ 1,949,580

(Dollars in thousands)

Reconciliation of segment income from operations to consolidated income before income tax (expense) benefit and equity losses of affiliates is as follows:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Total segment income from operations	$ 64,978	$ 74,628	$ 96,876
Interest expense	(46,960)	(53,666)	(64,525)
Mark-to-market loss on interest rate swaps	-	-	(112)
Interest income	992	3,531	3,011
Income before income tax (expense) benefit and equity in losses of affiliates	$ 19,010	$ 24,493	$ 35,250

Note 22. Related Party Transactions

On February 8, 2008, the Company acquired a 49% interest in the common stock of Target, a privately-held contract drilling company for $9,246. For the period February 8, 2008 to December 31, 2008, Target performed $7,282 of drilling and boring services for the Company. As of December 31, 2008 the Company had outstanding accounts payables of $407 related to Target.

Note 23. Lease Commitments

The Company leases office facilities, equipment and land under certain operating lease agreements that expire through 2028 and have various renewal options.

Minimum future rental commitments under noncancelable operating leases are set forth in the table below:

Year Ended December 31,	Operating Leases
2009	$ 3,786
2010	2,030
2011	962
2012	832
2013	645
Thereafter	2,124
Total Payments	$ 10,379

Rent expense and mineral royalties charged to *Cost of coal sales* were as follows:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Rent expense	$ 14,181	$ 10,691	$ 11,486
Mineral royalties	$ 86,137	$ 61,402	$ 59,667

(Dollars in thousands)

Note 24. Other Revenue

Other revenue consisted of the following:

	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006
Other revenue:			
Royalty income	$ 7,356	$ 5,017	$ 6,377
Synfuel fees	-	5,367	6,444
Coalbed methane	9,614	5,058	3,730
Transloading and plant processing fees	1,660	1,316	3,081
Gain on disposition of assets	1,565	5,185	876
Combined Benefit Fund refund	-	1,325	-
Dry Systems Technologies equipment and filter sales	8,200	4,214	5,345
Other	(1,345)	9,479	4,306
Total other revenue	$ 27,050	$ 36,961	$ 30,159

Note 25. Closed Mining Locations

The Company owns five mining locations that were closed in prior years due to geologic conditions or depletion of economic reserves. All these locations are currently in final reclamation at varying stages. Carrying values, which have been adjusted to fair value less costs to sell, include amounts for land and equipment of $1,056 and $1,425 as of December 31, 2008 and 2007, respectively. Timing of the sales for this land and equipment will depend on completion of reclamation and subsequent regulatory release and real estate and used equipment markets. These amounts are included in *Owned surface lands* and *Plant, equipment and mine development costs, net.*

Note 26. Concentration of Credit Risk and Major Customers

The Company markets its coal principally to electric utilities in the United States. As of December 31, 2008 and 2007, trade accounts receivable from electric utilities totaled approximately $118,929 and $80,888, respectively. Credit is extended based on an evaluation of the customer's financial condition and collateral is generally not required. Credit losses are provided for in the consolidated financial statements and historically have been minimal. The Company is committed under long-term contracts to supply coal that meets certain quality requirements at specified prices. The prices for some multi-year contracts are adjusted based on relevant economic indices or the contract may include year-to-year specified price changes. Qualities and volumes for the coal are stipulated in coal supply agreements. For the twelve months ended December 31, 2008, the Company's 10 largest customers accounted for approximately 55% of total coal sales with the largest customer being approximately 16%. The Northern Appalachia, Central Appalachia and Powder River Basin segments all reported revenue from the largest customer. For the twelve months ended December 31, 2007, the Company's 10 largest customers accounted for approximately 53% of total coal sales with the largest customer being approximately 13%. For the twelve months ended December 31, 2006, the Company's 10 largest customers accounted for approximately 49% of total coal sales with the largest customer being approximately 10%.

Note 27. Commitments and Contingencies

General

The Company follows SFAS No. 5, *Accounting for Contingencies*, in determining its accruals and disclosures with respect to loss contingencies. Accordingly, estimated losses from loss contingencies and legal expenses associated with the contingency are accrued by a charge to income when information available indicates that it is probable that an asset had been impaired or a liability had been incurred and the amount of the loss can be reasonably estimated. If a loss contingency is not probable or reasonably estimable, disclosure of the loss contingency is made in the consolidated financial statements when it is at least reasonably possible that a loss will be incurred and the loss is material.

Commitments

On February 20, 2008, the Company was determined to be the successful bidder on a federal coal lease by the Bureau of Land Management, a unit of the United States Department of the Interior. The bid was accepted as submitted in the amount of $180,540 for an approximate 1,428 acre tract of federal land. The lease became effective on May 1, 2008. This lease is subject to the deferred bonus payment provisions of the Code of Federal Regulations and, as such, the Company remits the bonus payment in five equal installments, the first of which was submitted with the bid as a deposit on the lease in February 2008. The remaining four annual installments of $36,108 each are due on the annual anniversary dates of the lease.

See Note 18 regarding our Asset Retirement Obligations.

Guarantees

Neweagle Industries, Inc., Neweagle Coal Sales Corp., Laurel Creek Co., Inc. and Rockspring Development, Inc. ("Sellers") are indirect wholly owned subsidiaries of the Company. The Sellers sell coal to Birchwood Power Partners, L.P. ("Birchwood") under a Coal Supply Agreement dated July 22, 1993 ("Birchwood Contract"). Laurel Creek Co., Inc. and Rockspring Development, Inc. were parties to the Birchwood Contract since its inception, at which time those entities were not affiliated with Neweagle Industries, Inc., Neweagle Coal Sales Corp. or the Company. Effective January 31, 1994, the Birchwood Contract was assigned to Neweagle Industries, Inc. and Neweagle Coal Sales Corp. by AgipCoal Holding USA, Inc. and AgipCoal Sales USA, Inc., which at the time were affiliates of Arch Coal, Inc. Despite this assignment, Arch Coal, Inc. ("Arch") and its affiliates have separate contractual obligations to provide coal to Birchwood if Sellers fail to perform. Pursuant to an Agreement & Release dated September 30, 1997, the Company agreed to defend, indemnify and hold harmless Arch and its subsidiaries from and against any claims arising out of any failure of Sellers to perform under the Birchwood Contract. By acknowledgement dated February 16, 2005, the Company and Arch acknowledged the continuing validity and effect of said Agreement & Release.

In the normal course of business, the Company is a party to guarantees and financial instruments with off-balance sheet risk, such as bank letters of credit, performance or surety bonds and other guarantees and indemnities related to the obligations of affiliated entities, which are not reflected in the accompanying Consolidated Balance Sheets. Management does not expect any material losses to result from these guarantees and other off-balance sheet instruments.

Contingencies

Extensive regulation of the impacts of mining on the environment and of maintaining workplace safety, and related litigation, has had or may have a significant effect on the Company's costs of production and results of operations. Further regulations, legislation or litigation in these areas may also cause the Company's sales or profitability to decline by increasing costs or by hindering the Company's ability to continue mining at existing operations or to permit new operations.

(Dollars in thousands)

Legal Proceedings

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

Letters of Credit

At December 31, 2008, the Company had $170,870 of letters of credit outstanding under its revolving credit facility.

Note 28. Unaudited Supplementary Data

The following is a summary of selected quarterly financial information (unaudited):

	2008			
	Three Months Ended December 31,	Three Months Ended September 30,	Three Months Ended June 30,	Three Months Ended March 31,
Revenues	$ 456,522	$ 409,367	$ 411,937	$ 412,304
Income (loss) from operations	$ 59,421 (1)	$ (24,223) (2)	$ 8,687 (3)	$ 21,093
Net income (loss)	$ 42,036	$ (32,225)	$ (4,427)	$ 6,170
Basic earnings (loss) per common share	$ 0.94	$ (0.71)	$ (0.10)	$ 0.14
Diluted earnings (loss) per common share	$ 0.93	$ (0.71)	$ (0.10)	$ 0.13
Weighted-average shares-basic	44,543,934	45,345,400	45,397,449	45,009,728
Weighted-average shares-diluted	45,274,333	45,345,400	45,397,449	46,259,336
Closing price of common stock	$ 14.02	$ 35.58	$ 88.58	$ 50.33

(1) Includes $2,207 net change in fair value of derivative instruments. See Note 16.
(2) Includes ($12,715) net change in fair value of derivative instruments. See Note 16.
(3) Includes $1,062 net change in fair value of derivative instruments. See Note 16.

	2007			
	Three Months Ended December 31,	Three Months Ended September 30,	Three Months Ended June 30,	Three Months Ended March 31,
Revenues	$ 367,202	$ 359,058	$ 368,481	$ 394,922
Income from operations	$ 22,140	$ 8,026 (1)	$ 2,187 (2)	$ 42,275 (3)
Net income (loss)	$ 9,933	$ 1,905	$ (3,785)	$ 24,554
Basic earnings (loss) per common share	$ 0.22	$ 0.04	$ (0.08)	$ 0.54
Diluted earnings (loss) per common share	$ 0.21	$ 0.04	$ (0.08)	$ 0.53
Weighted-average shares-basic	45,046,788	45,221,193	45,236,870	45,121,903
Weighted-average shares-diluted	46,290,178	46,412,804	45,236,870	46,387,018
Closing price of common stock	`$ 52.50	$ 39.20	$ 40.64	$ 34.34

(1) Includes $2,314 of employee termination costs associated with the idling of the Wabash mine. See Note 3.
(2) Includes $9,731 of employee and contract termination costs associated with the idling of the Wabash mine. See Note 3.
(3) Includes $2,252 of employee termination costs associated with the idling of the Wabash mine. See Note 3.

Note 29. Subsequent Events

On January 30, 2009, an affiliate of the Company idled the Laurel Creek mining complex, which produced approximately 1.0 million clean tons of coal in 2008, and consists of three underground mines and an associated preparation plant. As of December 31, 2008, the Laurel Creek mining complex had approximately 33.0 million tons of proven and probable reserves, consisting of approximately 18.0 million tons of surface reserves and approximately 15.0 million tons of underground reserves. The decision to idle the Laurel Creek mining complex was due to certain business conditions. During the first quarter of 2009 the Company expects to record approximately $2,100 in employee severance and medical continuance costs in accordance with SFAS No. 146. The Laurel Creek mining complex is included in the Company's Central Appalachia segment. See Note 21.

As of December 31, 2008, management performed an impairment assessment with respect to the long-lived asset group at the Laurel Creek mining complex. The Company's assessment focused on the future cash flows of continuing to operate Laurel Creek mining complex under a number of scenarios, including as a surface-only mine. As a result of this review, management concluded that the Laurel Creek mining complex asset group was not impaired at December 31, 2008 based upon the provisions of SFAS No. 144.

On February 26, 2009, the Board declared a quarterly dividend of $0.05 per share on the Company's common stock payable on March 27, 2009 to shareholders of record on March 17, 2009.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 (the "Act"), as amended, is recorded, processed, evaluated, summarized and reported accurately within the time periods specified in the Securities and Exchange Commission's rules and forms. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As of the end of the period covered by this report, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(e) and 15d-15(e). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective and are designed to (a) ensure that information required to be disclosed by us in reports we file or submit under the Act are recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; and (b) ensure that information required to be disclosed by us in reports filed or submitted under the Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There has been no change in the Company's internal control over financial reporting during the most recent fiscal quarter that has materially affected, or that is reasonably likely to materially affect the Company's internal control over financial reporting.

Internal Control over Financial Reporting

Management's report on internal control over financial reporting and the report of the Company's Independent Registered Public Accounting Firm on internal control over financial reporting are included in "ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA."

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The sections of our 2008 Proxy Statement entitled "Nominees for Directors," "Director Independence," "Board and its Committees," "Executive Officers," "Section 16(a) Beneficial Ownership Reporting Compliance," and "Code of Business Conduct and Ethics" are incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION.

The sections of our 2008 Proxy Statement entitled "Corporate Governance and Related Matters—Director Compensation," "Compensation Committee Interlocks and Insider Participation," "Executive Compensation and Related Information—Summary Compensation Table," "Executive Compensation and Related Information—Grants of Plan Based Awards," "Executive Compensation and Related Information—Outstanding Equity Awards at Fiscal Year-End," "Executive Compensation and related Information—Compensation Discussion and Analysis," "Executive Compensation and Related Information—Compensation Committee Report," "Executive Compensation and Related Information—Option Exercises and Stock Vested," "Executive Compensation and Related Information—Potential Post-Employment Payments," and "Executive Compensation and Related Information—Pension Plan Information," are incorporated herein by reference.

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

The sections of our 2008 Proxy Statement entitled "Executive Compensation and Related Information—Equity Compensation Plan Information," and "Stock Ownership—Ownership by largest holders, directors and officers" are incorporated herein by reference.

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

The section of our 2008 Proxy Statement entitled "Certain Relationships and Related Transactions", "Corporate Governance and Related Matters—Director Independence" and "Corporate Governance and Related Matters—Independence Considerations" are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The section of our 2008 Proxy Statement entitled "Fees of Independent Accountants" is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

15(a)(1) Consolidated Financial Statements

The financial statements filed as part of this report are included in the Index to the Financial Statements under ITEM 8 of this Annual Report on Form 10-K.

15(a)(2) Financial Statement Schedules

Except as set forth below, all other schedules are omitted because they are not required or because the information is provided elsewhere in the Consolidated Financial Statements and Notes thereto.

Foundation Coal Holdings, Inc. and Subsidiaries

Schedule II—Valuation and Qualifying Accounts

(Dollars in thousands)

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[1]	Other	Balance at End of Period
			(in thousands)		
Twelve Months Ended December 31, 2008					
Reserves deducted from asset accounts:					
Reserve for material and supplies[2]	$ 6,622	$ 1,486	$ -	$ -	$ 8,108
Valuation allowance for deferred tax assets[4]	48,732	26,358	-	24,860	99,950
Twelve Months Ended December 31, 2007					
Reserves deducted from asset accounts:					
Reserve for material and supplies[2]	$ 5,100	$ 526	$ -	$ 996	$ 6,622
Valuation allowance for deferred tax assets	42,292	6,440	-	-	48,732
Allowance for long-term note receivables	30	-	(30)	-	-
Twelve Months Ended December 31, 2006					
Reserves deducted from asset accounts:					
Reserve for material and supplies[2]	$ 8,038	$ -	$(2,938)	$ -	$ 5,100
Valuation allowance for deferred tax assets[3]	28,073	7,624	-	6,595	42,292
Allowance for long-term note receivables	118	-	(88)	-	30

(1) Reserves utilized.

(2) Net change in reserve for obsolescence based on carrying value of the material and supplies inventory and the length of time the items are maintained in the inventory.

(3) During 2006, the Company recorded a valuation allowance of $7,624 for the difference between the federal regular tax rate and alternative minimum tax rate attributable to the Company's net deferred tax asset. Other changes in the valuation allowance were the result of recognizing the gross value of certain state deferred tax assets, including net operating losses, that required a valuation allowance.

(4) Primarily represents valuation allowance not allocated to 2008 earnings in accordance with the intraperiod tax allocation provisions of SFAS No. 109.

15(a)(3) Exhibits.

EXHIBIT INDEX

Exhibit No.	Description of Exhibit
2.1	Stock Purchase Agreement, dated as of May 24, 2004, between RAG Coal International AG and Foundation Coal Corporation (formerly known as American Coal Acquisition Corp.), previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference.
2.2	Agreement and Plan of Merger, dated as of August 9, 2004, between Foundation Coal Holdings, LLC and the Company, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference.
3.1	Form of Third Amended and Restated Certificate of Incorporation of the Company, previously filed as an exhibit to the Company's Form 10-Q on August 9, 2006 and incorporated by reference.
3.2	Form of Amended and Restated By-laws of the Company, previously filed as an exhibit to the Company's Form 8-K on May 22, 2006, and incorporated by reference.
4.1*	Form of certificate of the Company common stock.
4.2	Amended and Restated Stockholders Agreement, dated as of October 4, 2004, by and among the Company, Blackstone FCH Capital Partners IV, L.P., Blackstone Family Investment Partnership IV-A L.P., First Reserve Fund IX, L.P., AMCI Acquisition, LLC and the management stockholders parties thereto, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference.
4.2.1	Termination Agreement, dated as of February 6, 2006, by and among the Company, Blackstone FCH Capital Partners IV, L.P., Blackstone Family Investment Partnership IV-A L.P., First Reserve Fund IX, L.P., AMCI Acquisition, LLC (nka AMCI Acquisition III, LLC), and the management stockholders parties thereto, terminating the Amended and Restated Stockholders Agreement dated as of October 4, 2004, by and among the same parties, previously filed as an exhibit to the Company's Form 8-K on February 23, 2006 and incorporated by reference.
4.3	Senior Notes Indenture, dated as of July 30, 2004, among Foundation PA Coal Company (nka Foundation PA Coal Company, LLC), the Guarantors named therein and The Bank of New York, as Trustee, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference.
4.3.1	Supplemental Indenture dated as of September 6, 2005 among Foundation Mining LP, a subsidiary of Foundation Coal Corporation, Foundation PA Coal Company, LLC and The Bank of New York, as Trustee, previously filed as an exhibit to the Company's Form 10-Q on November 14, 2005 and incorporated by reference.
4.3.2	Supplemental Indenture dated as of October 5, 2007 among Foundation PA Coal Terminal, LLC, a subsidiary of Foundation Coal Corporation, Foundation PA Coal Company, LLC and The Bank of New York, as Trustee, previously filed as an exhibit to the Company's Form 10-Q on November 9, 2007 and incorporated by reference.
10.1	Credit Agreement dated as of July 30, 2004, as amended and restated as of July 7, 2006 by and among Foundation Coal Corporation, Foundation PA Coal Company, LLC, the Lenders named therein and Citicorp North America, Inc. as Administrative Agent and Collateral Agent and the Issuing Banks and other agents party thereto, previously filed as an exhibit to the Company's Form 8-K on July 13, 2006, and incorporated by reference.

Exhibit No.	Description of Exhibit
10.2	Guarantee and Collateral Agreement, dated as of July 30, 2004, among FC2 Corp., Foundation Coal Corporation, Foundation PA Coal Company (nka Foundation PA Coal Company, LLC) as Borrower, the Subsidiary Parties party thereto and Citicorp North America, Inc., as Collateral Agent, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference.
10.2.1	Supplement Number 1 dated as of September 2, 2005, to the Guarantee and Collateral Agreement dated as of July 30, 2004, among FC2 Corp., Foundation Coal Corporation, Foundation PA Coal Company, LLC as Borrower, the Subsidiary Parties thereto and Citicorp North America, Inc. as Collateral Agent, previously filed as an exhibit to the Company's Form 10-Q on November 14, 2005 and incorporated by reference
10.2.2	Supplement Number 2 dated as of October 5, 2007, to the Guarantee and Collateral Agreement dated as of July 30, 2004, among FC2 Corp., Foundation Coal Corporation, Foundation PA Coal Company, LLC as Borrower, the Subsidiary Parties thereto and Citicorp North America, Inc. as Collateral Agent, previously filed as an exhibit to the Company's Form 10-Q on November 9, 2007 and incorporated by reference
10.3	Registration Rights Agreement dated as of July 30, 2004, by and between Foundation Coal Holdings, LLC., a Delaware limited liability company, the Sponsor Stockholders, the Investor Stockholders and the Management Stockholders and any other Person that shall from and after the date hereof acquire or otherwise be the transferee, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference.
10.4	The Company's Amended and Restated 2004 Stock Incentive Plan, as amended and restated March 8, 2008, previously filed as an exhibit to the Company's Form 8-K on May 29, 2008 and incorporated by reference.
10.5	The Company's 2008 Annual Incentive Performance Plan, dated as of March 8, 2008, previously filed as an exhibit to the Company's Form 8-K on May 29, 2008 and incorporated by reference.
10.6	Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and James F. Roberts, previously filed as an exhibit to the Company's Form 8-K on March 14, 2006 and incorporated by reference.
10.6.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and James F. Roberts, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.7	Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Frank J. Wood, previously filed as an exhibit to the Company's Form 8-K on March 14, 2006 and incorporated by reference.
10.7.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Frank J. Wood , previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.8	Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and James J. Bryja, previously filed as an exhibit to the Company's Form 8-K on March 14, 2006 and incorporated by reference.

Exhibit No.	Description of Exhibit
10.8.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and James J. Bryja, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.8.2	Amendment Number 2, dated June 18, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and James J. Bryja, previously filed as an exhibit to the Company's Form 10-Q on August 9, 2007 and incorporated by reference.
10.9	Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Kurt D. Kost, previously filed as an exhibit to the Company's Form 8-K on March 14, 2006 and incorporated by reference.
10.9.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Kurt D. Kost, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.9.2	Amendment Number 2, dated June 18, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Kurt D. Kost, previously filed as an exhibit to the Company's Form 10-Q on August 9, 2007 and incorporated by reference.
10.10	Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Greg A. Walker, previously filed as an exhibit to the Company's Form 8-K on March 14, 2006 and incorporated by reference.
10.10.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Greg A. Walker, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.11	Amended and Restated Employment Agreement dated as of September 27, 2006 by and between Foundation Coal Corporation and Allen S. Pack, Jr., previously filed as an exhibit to the Company's Form 8-K on October 2, 2006, and incorporated by reference.
10.11.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated September 27, 2006, by and between Foundation Coal Corporation and Allen S. Pack, Jr., previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.12	Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and James A. Olsen, previously filed as an exhibit to the Company's Form 8-K on March 14, 2006 and incorporated by reference.
10.12.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and James A. Olsen, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.13	Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Michael R. Peelish, previously filed as an exhibit to the Company's Form 8-K on March 14, 2006 and incorporated by reference.

Exhibit No.	Description of Exhibit
10.13.1	Amendment Number 1, dated January 3, 2007, to Amended and Restated Employment Agreement, dated March 13, 2006, by and between Foundation Coal Corporation and Michael R. Peelish, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.14	Federal Coal Lease WYW-0317682: Belle Ayr Mine, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference
10.15	Federal Coal Lease WYW-78629: Belle Ayr Mine, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference
10.16	Federal Coal Lease WYW-80954: Belle Ayr Mine, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference
10.17	Federal Coal Lease WYW-0313773: Eagle Butte Mine, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference
10.18	Federal Coal Lease WYW-78631: Eagle Butte Mine, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference
10.19	Federal Coal Lease WYW-124783: Eagle Butte Mine, previously filed as an exhibit to the Company's Registration Statement on Form S-1 (File No. 333-118427) and incorporated by reference
10.20	Federal Coal Lease WYW 1155132: Eagle Butte Mine, previously filed as an exhibit to the Company's Form 10-Q on May 9, 2008 and incorporated by reference.
10.21	Form of Independent Directors Initial Restricted Stock Agreement, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.22	Form of Independent Directors Annual Restricted Stock Agreement, previously filed as an exhibit to the Company's Form 10-K on March 1, 2007 and incorporated by reference.
10.23	Form of Executive Officer Non-Qualified Stock Option Agreement, previously filed as an exhibit to the Company's Form 10-Q on November 14, 2005, and incorporated by reference.
10.23.1	Form of Amendment Number 1 to Executive Officer Non-Qualified Stock Option Agreement, previously filed as an exhibit to the Company's Form 10-Q on November 14, 2005, and incorporated by reference.
10.24	Restricted Stock Unit Agreement dated as of March 18, 2005 by and between the Company and Kurt D. Kost, previously filed as an exhibit to the Company's Form 8-K on December 12, 2005 and incorporated by reference.
10.24.1	Restricted Stock Unit Agreement dated as of December 7, 2005 by and between the Company and Kurt D. Kost, previously filed as an exhibit to the Company's Form 8-K on December 12, 2005 and incorporated by reference.
10.24.2	Restricted Stock Unit Agreement, approved June 18, 2007, and executed June 29, 2007, by and between the Company and Kurt D. Kost, previously filed as an exhibit to the Company's Form 10-Q on August 9, 2007 and incorporated by reference.

Exhibit No.	Description of Exhibit
10.25	Restricted Stock Unit Agreement dated as of March 18, 2005 by and between the Company and Allen S. Pack, Jr., previously filed as an exhibit to the Company's Form 8-K on May 23, 2006, and incorporated by reference.
10.25.1	Restricted Stock Unit Agreement dated as of February 28, 2006 by and between the Company and Allen S. Pack, Jr., previously filed as an exhibit to the Company's Form 8-K on May 23, 2006, and incorporated by reference.
10.25.2	Restricted Stock Unit Agreement dated as of July 1, 2006 by and between the Company and Allen S. Pack, Jr., previously filed as an exhibit to the Company's Form 8-K on July 7, 2006, and incorporated by reference.
12.1*	Statement re computation of Ratio of Earnings to Fix Charges.
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP.
24.1*	Powers of Attorney.
31.1*	Certification of periodic report by the Company's Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of periodic report by the Company's Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of periodic report by the Company's Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of periodic report by the Company's Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: March 2, 2009

FOUNDATION COAL HOLDINGS, INC.
(Registrant)

Name	Title
/s/ JAMES F. ROBERTS **James F. Roberts**	Chief Executive Officer and Chairman (Principal Executive Officer)
/s/ FRANK J. WOOD **Frank J. Wood**	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
/s/ KURT D. KOST **Kurt D. Kost**	President and Chief Operating Officer
* **David I. Foley**	Director
* **Alex T. Krueger**	Director
* **William J. Crowley, Jr.**	Director
* **Joel Richards, III**	Director
* **P. Michael Giftos**	Director
* **Robert C. Scharp**	Director
* **Thomas V. Shockley, III**	Director
*/s/ GREG A. WALKER ***Greg A. Walker, Attorney-in-fact**	

INVESTOR INFORMATION

Stock Listing

The common shares of Foundation Coal Holdings, Inc. are traded on the New York Stock Exchange under the ticker symbol FCL.

Corporate Headquarters

Foundation Coal Holdings, Inc.
999 Corporate Boulevard, Suite 300
Linthicum Heights, MD 21090
Phone: (410) 689-7500
www.foundationcoal.com

Financial Information

For additional information, please refer to www.foundationcoal.com or contact Foundation Coal at our corporate office.

Transfer Agent & Registrar

BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, NJ 07310-1900
(877) 296-3711 (in the U.S.)
(201) 680-6685 (outside the U.S.)
(800) 231-5469 (hearing impaired-TTD Phone)
www.bnymellon.com/shareowner/isd.

General inquiries and address changes:
BNY Mellon Shareowner Services
480 Washington Boulevard, 27th Fl.
Jersey City, NJ 07310-1900
Email: shrrelations@mellon.com

Send Certificates For Transfer to:
BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, PA 15252-8015

Auditors

Ernst & Young LLP
621 East Pratt Street
Baltimore, MD 21202
Phone: (410) 539-7940
Fax: (410) 783-3832

Dividends

Foundation Coal pays quarterly dividends on common stock, subject to the approval of the Board of Directors.

Annual Meeting

Foundation Coal Holdings, Inc. will hold its annual shareholder meeting at the Westin Baltimore Washington Airport Hotel, 1100 Old Elkridge Landing Rd., Linthicum Heights, MD on Wednesday, May 13 at 10 AM.

Forward-Looking Statements

Certain statements relating to the future prospects, developments, business strategies, analyses and other information that is based on forecasts of future results and estimates of amounts not yet determinable are forward-looking statements (as such term is defined in the Private Securities Litigation Reform Act of 1995) which can be identified as any statement that does not relate strictly to historical or current facts. The company has used the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project" and similar terms and phrases, including references to assumptions, to identify forward-looking statements. These forward-looking statements are made based on expectations and beliefs concerning future events affecting the company and are subject to uncertainties and factors relating to the company's operations and business environment, all of which are difficult to predict and many of which are beyond the company's control, that could cause the company's actual results to differ materially from those matters expressed in or implied by these forward-looking statements. These factors include, but are not limited to: market demand for coal, electricity and steel; weather conditions or catastrophic weather-related damage; the company's production capabilities; timing of reductions or increases in customer coal inventories; long-term coal supply arrangements; environmental laws, including those directly affecting the company's coal mining and production, and those affecting the company's customers' coal usage; regulatory and court decisions; railroad, barge, trucking and other transportation performance and costs; our assumptions concerning economically recoverable coal reserve estimates; employee workforce factors; changes in postretirement benefit and pension obligations; the company's liquidity, results of operations and financial condition. The company advises investors that it discusses additional risk factors and uncertainties that could cause Foundation Coal Holdings, Inc. actual results to differ from forward-looking statements in the company's Form 10-K included with this Annual Report filed with the Securities and Exchange Commission ("SEC") under the heading "Risk Factors". The investor should keep in mind that any forward-looking statement made by the company in this Annual Report or elsewhere speaks only as of the date on which the company makes it. New risks and uncertainties come up from time to time, and it is impossible for the company to predict these events or how they may affect the company. The company has no duty to, and does not intend to, update or revise the forward-looking statements in this Annual Report, except as may be required by law. In light of these risks and uncertainties, the investor should keep in mind that any forward-looking statement made in this Annual Report or elsewhere might not occur.

Unless the context otherwise indicates, as used in this Annual Report the terms "we" "our" "us" and similar terms refer to Foundation Coal Holdings, Inc. and its consolidated subsidiaries.

In June 2008, the Company submitted without qualification a Chief Executive Officer certification to the New York Stock Exchange in which the Company's Chief Executive Officer certified that he was not aware of any violation by the Company of NYSE corporate governance listing standards as of the date of the certification. In addition, Sarbanes-Oxley Act Section 302 certifications regarding the quality of the Company's public disclosure were executed by each of the Company's Chief Executive Officer and Chief Financial Officer and are included as exhibits 31.1 and 31.2 respectively to the Company's Form 10-K for the fiscal year ended December 31, 2008.

Design and development: www.sirendesign.com

FOUNDATION COAL HOLDINGS, INC.
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