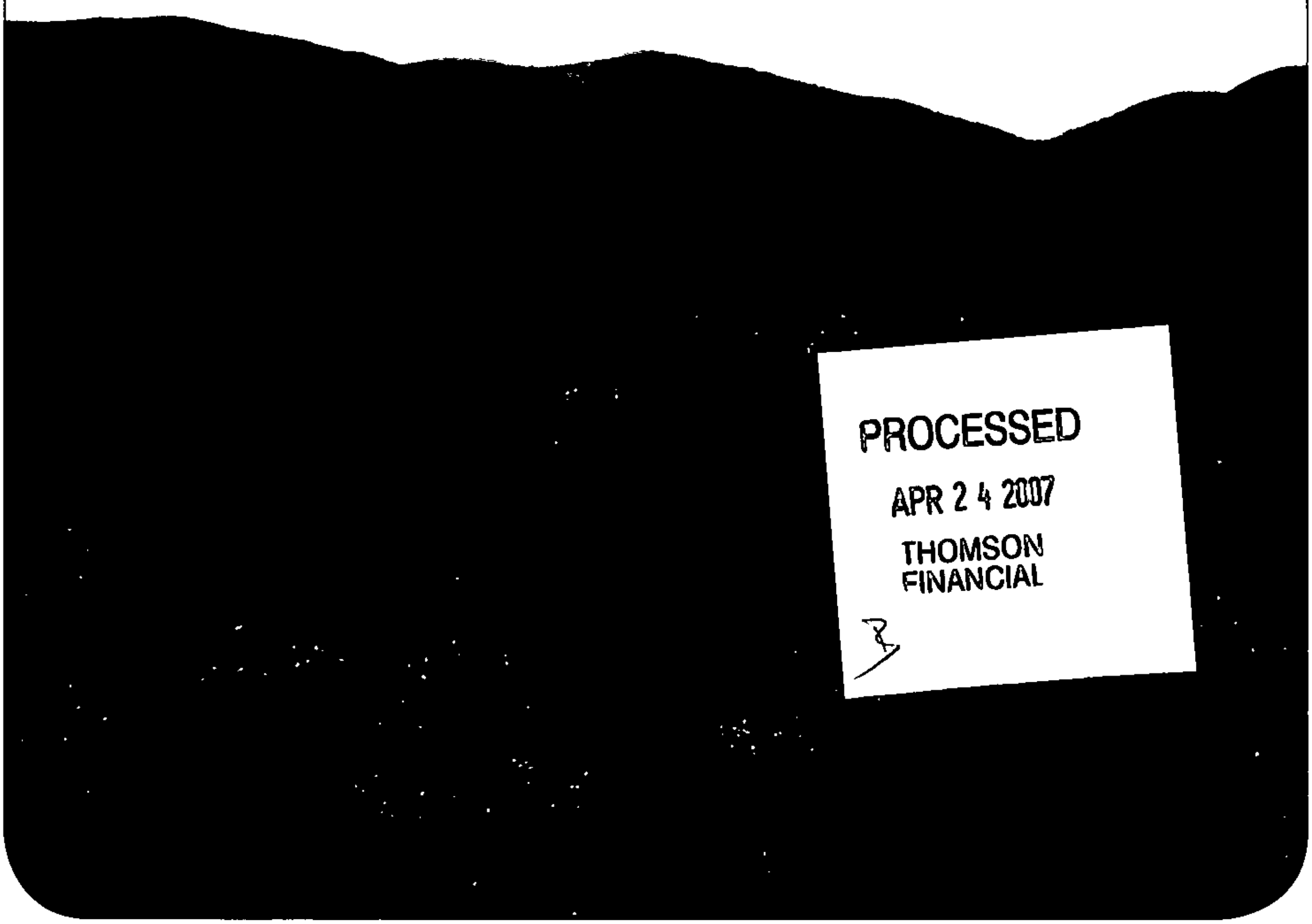
Massey Energy®

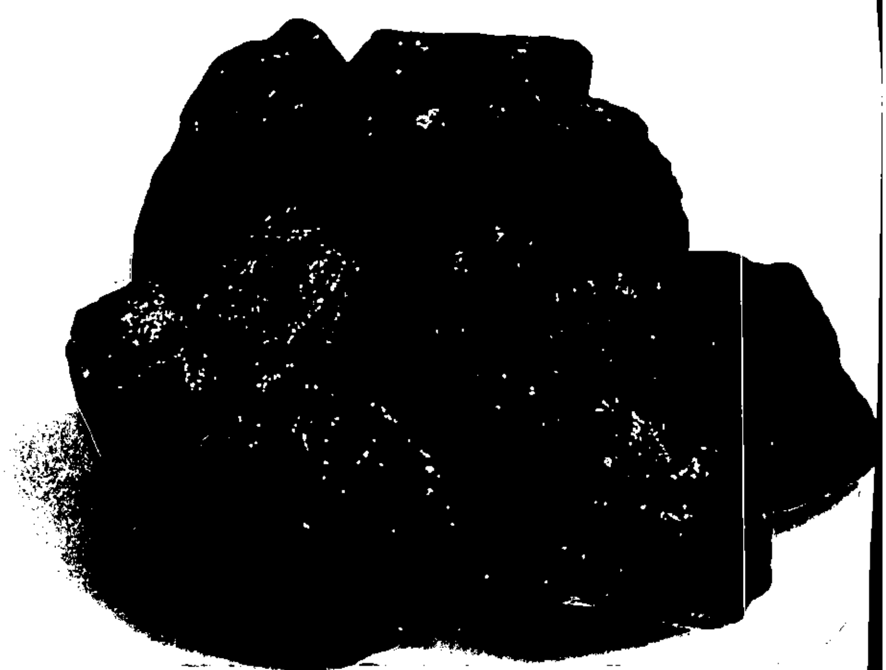
The energy is here.

2006 Annual Report



and Central Appalachia.

Massey Energy mines, processes and sells high-quality, low sulfur coal for electricity generation, steel making and industrial applications. We are America's fourth-largest producer of coal by revenues and the largest in Central Appalachia. We are also the largest supplier of metallurgical coal to the American steel industry. With 22 modern mining complexes located in southern West Virginia, eastern Kentucky and southwestern Virginia, Massey is well-positioned to serve the energy needs of coal consumers throughout the eastern United States and Canada.



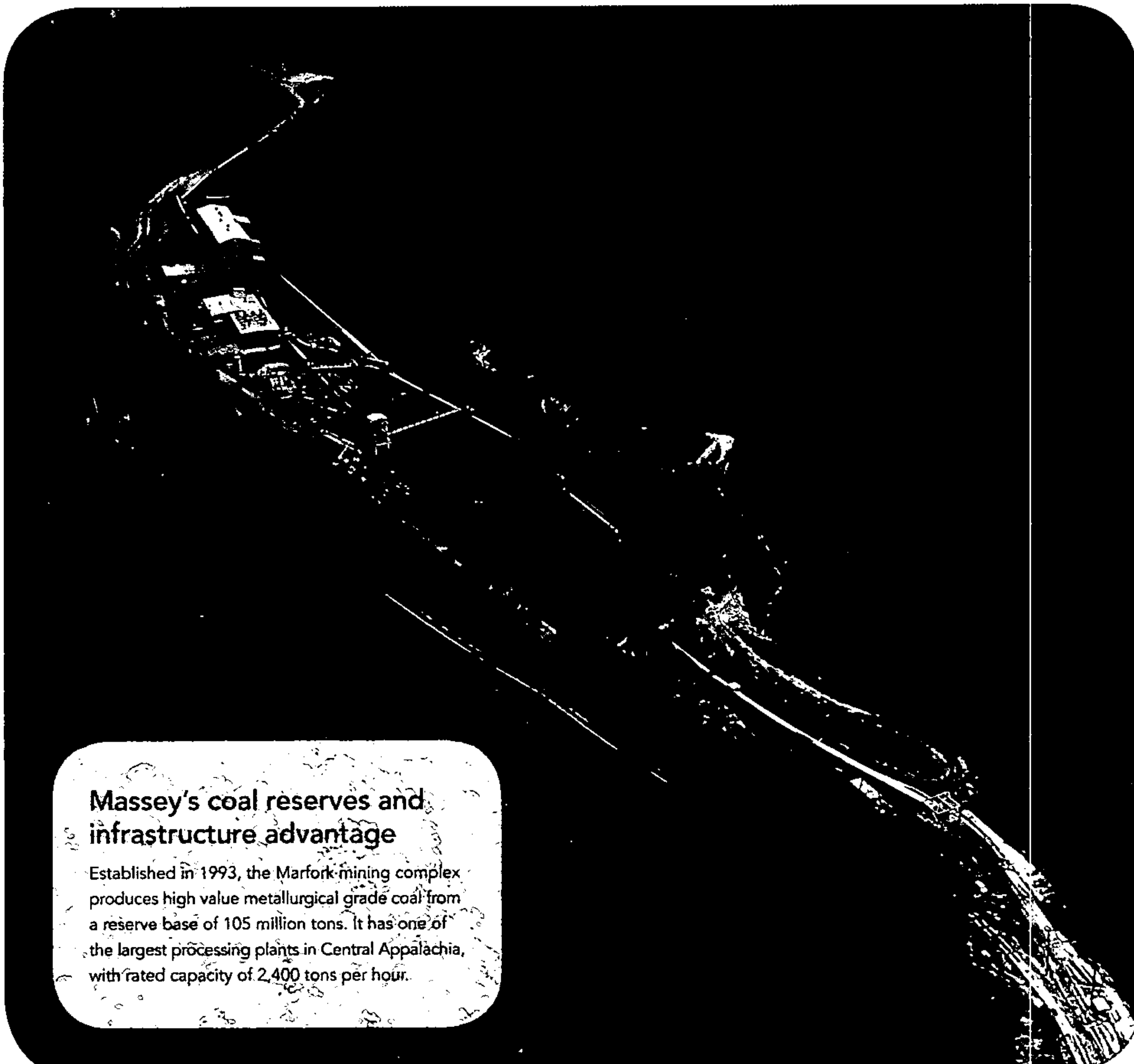
Massey Energy and Central Appalachia

The Central Appalachia region reaches from southern West Virginia into Kentucky, Virginia and Tennessee. It's a region steeped in coal mining history – a people and an energy resource that have been supplying the country's energy needs for over 150 years.

In Central Appalachia, Massey Energy is the foremost coal producer – we produce approximately twice the tonnage of any other producer in the region, and we produce it more safely, more efficiently and at a lower cost than our competitors. The energy that Central Appalachia and Massey Energy produce delivers value to our customers, our communities, our members and our shareholders.

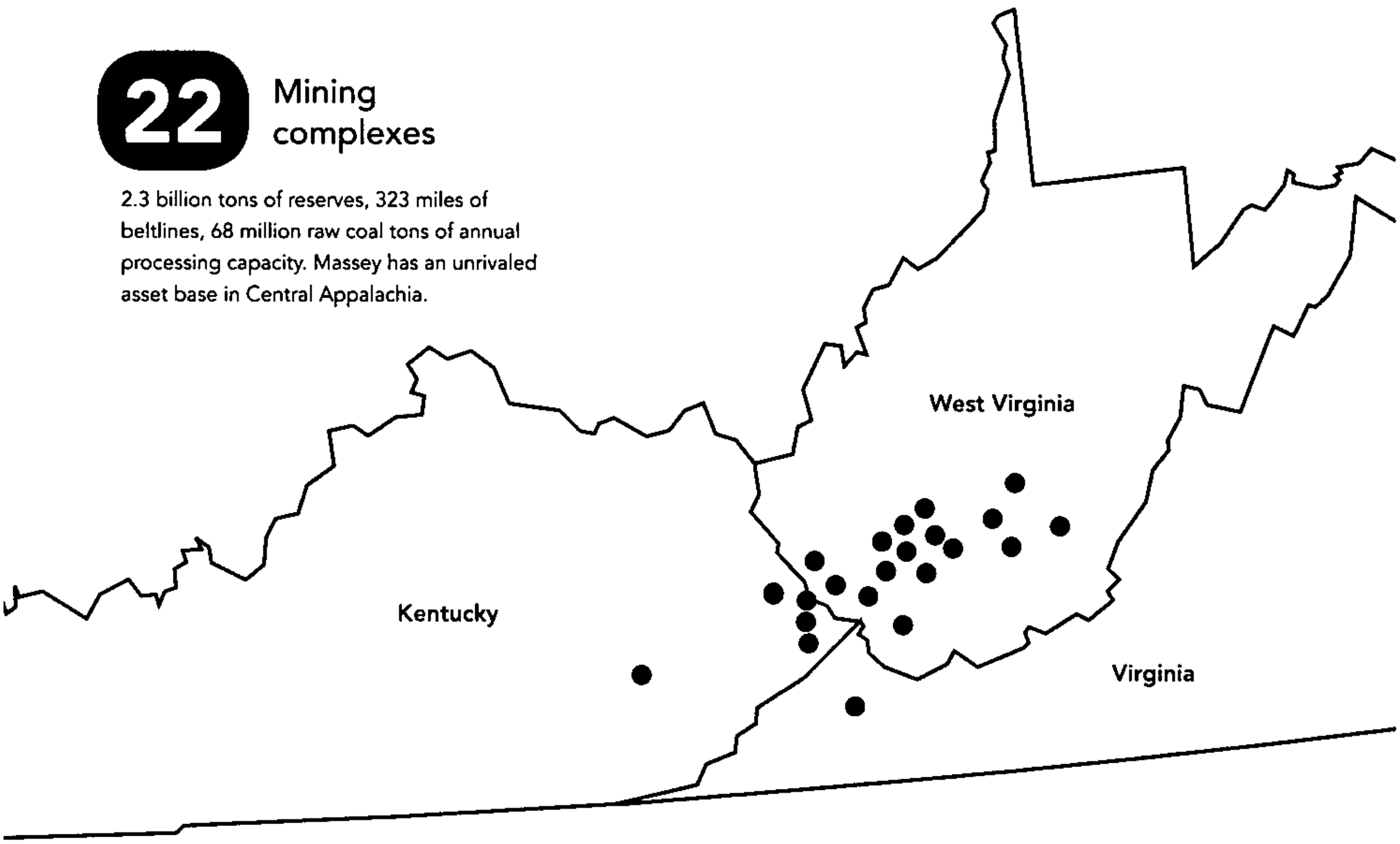
A resource equivalent to 25 billion barrels of oil.

The energy is here.



Massey's coal reserves and infrastructure advantage

Established in 1993, the Marfork mining complex produces high value metallurgical grade coal from a reserve base of 105 million tons. It has one of the largest processing plants in Central Appalachia, with rated capacity of 2,400 tons per hour.



A unique energy resource. In Central Appalachia, there are approximately six billion tons of premium coal reserves containing 150 quadrillion Btu of energy. This is roughly equal to the energy content of all the proved oil reserves in the Unites States.

Massey controls a third of these coal reserves – more than three times that of our nearest competitor. At the current rate of production, we have sufficient reserves to last over 50 years. The rest of Central Appalachia's reserves will last about 20 years at their current rate of production. Because Central Appalachian coal reserves are a finite and depleting resource, having access to ample reserves is critical to the future of the Company. Furthermore, having reserves that are relatively lower cost to mine than our competitors' reserves gives Massey a competitive advantage for years to come.

This unparalleled asset base has been accumulated over decades of disciplined acquisitions. We have opportunistically grown the Company from 720 million tons of reserves 20 years ago to 2.3 billion tons today – tripling our reserve base. Not only has Massey increased its reserve position, but we have also continued to develop our related infrastructure to keep our low-cost advantage. Our fleet of surface mine earth-moving equipment has expanded fivefold in the past 10 years. We have invested in highly efficient processing plants and cost-saving coal conveyor beltlines. Massey accomplished all of this while maintaining low legacy liabilities, a strong balance sheet and a cohesive asset portfolio with immense strategic value.

We have also been disciplined managers of our assets, divesting non-strategic properties when attractive opportunities have become available. Since 2000, we have divested $162 million of assets, earning $127 million in before-tax profits. Going forward, we will continue to capitalize on acquisition and divestiture opportunities to create value within our portfolio of reserves.

Production to serve the world.

The energy is here.

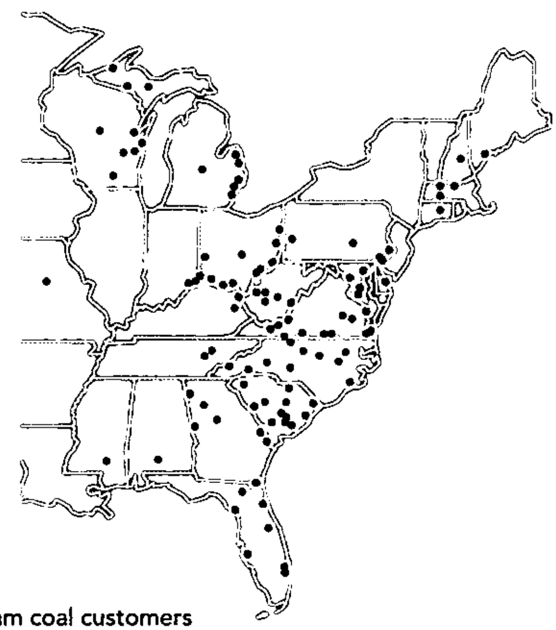
Powering people everywhere. Massey produced 39 million tons of Central Appalachian coal in 2006 – approximately twice the amount of our nearest competitor in the region. This coal went to Florida to generate electricity, Brazil to manufacture steel, Michigan to produce paper and other destinations all over the world to provide energy for our customers.

Steam coal. Steam coal is used by utilities and industrial companies to produce heat and electricity. Central Appalachian steam coal is the highest-valued steam coal in the United States due to its high-energy, low sulfur content and its proximity to utilities serving the eastern U.S. markets.

In 2006, 80% of Massey's production was sold as steam coal. Of this amount, Massey produced and sold 27.7 million tons of coal to utilities – enough to provide electricity for more than five million households during the year.

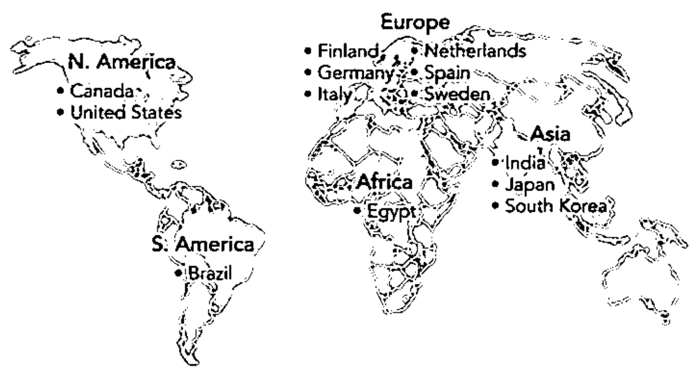
Metallurgical coal. Metallurgical coal is used to produce coke, the key energy ingredient in the steel-making process. Central Appalachian metallurgical coal is some of the highest-quality metallurgical coal in the world and is exported as far away as Asia, Europe and South America.

In 2006, 20% of Massey's production was sold as metallurgical coal. Massey is one of the largest producers of metallurgical coal in the United States.



Steam coal customers

In 2006, Massey shipped 31.3 million tons of steam coal to 76 customers concentrated in the eastern U.S. markets.



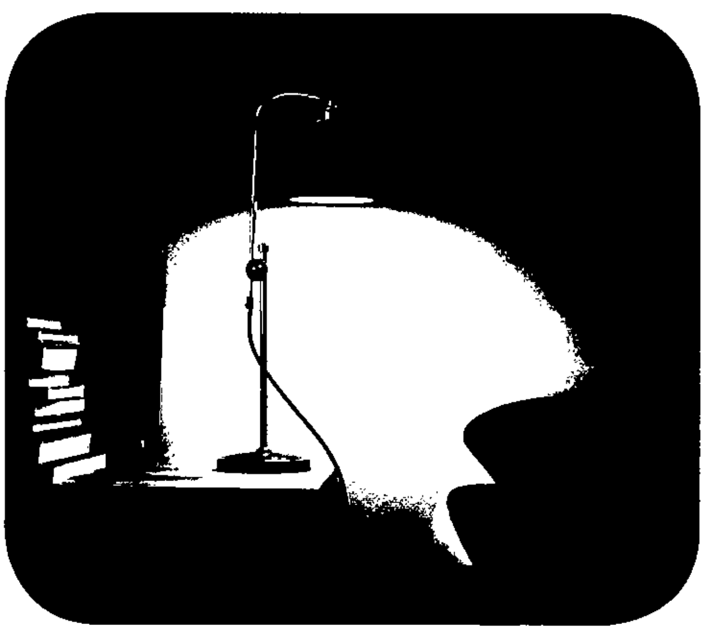
Metallurgical coal customers

In 2006, Massey shipped 7.8 million tons of metallurgical coal to 25 customers located around the world.

In 2006, coal supplied about half the electricity generated in the United States.

On average, each person in the United States uses 3.8 tons of coal a year.

Central Appalachian coal is used to power millions of American homes and businesses, to produce steel around the world and to manufacture everyday consumer products like toothpaste and paper. In the future, it is even projected to produce liquid fuels for our automobiles. Coal is an abundant and economical domestic source of energy that we depend on to support our modern lifestyles.



A proud tradition of coal mining.

The energy is here.

Our roots here run deep. Coal has been mined in Central Appalachia for generations. Today there are approximately 30,000 coal miners in the region, and much has changed since the early years of coal mining. Modern Central Appalachian coal mining requires highly skilled professionals to operate and maintain the technologically advanced mining equipment. In room and pillar underground mines, small teams of miners coordinate movements among the continuous miner that mines the coal, the roof bolter that secures the overhead rock and the shuttle car that hauls the coal. The team's ability to accomplish their mission safely and efficiently determines our success in underground mining. On surface mines, Central Appalachian coal miners operate large bulldozers, trucks, shovels and draglines. Massey members have the advantage of working with some of the most efficient surface mining equipment in the region.

The Company has been mining coal in Central Appalachia for 50 years under the Massey name – longer than any other Central Appalachian coal company. Today our company has over 5,400 members. Among them are some of the most productive and highly skilled coal miners in the region. A Massey coal miner produces, on average, 3.8 tons of coal an hour – 10% more than the average Central Appalachian coal miner. This efficiency is achieved by training every Massey coal miner in our S-1, P-2 and M-3 standards – Safety is Job One, Productivity is Job Two and Measurement is Job Three. These standards embody decades of Massey's Central Appalachian mining expertise and experience distilled into a mining methodology that keeps our members safe and productive.

S-1 Standard – prescribes safety measures that go well beyond legal requirements
P-2 Standard – promotes the application of best production practices
M-3 Standard – requires that managers receive timely and accurate information to make the best business decisions possible

A new generation of Central Appalachian coal miners has entered the industry in the past several years to help supply the strong demand for the region's coal. West Virginia began 2005 with 14,000 active coal miners. Since then, West Virginia has issued 8,000 new miner certifications. We at Massey, and the region overall, have faced challenges in maintaining productivity while incorporating new members. However, Massey's training, mentor programs and S-1, P-2 and M-3 standards are building our new members into productive coal miners, just as they have with past generations of Massey members. This investment in our people will pay dividends in 2007 and beyond.

A higher standard in coal mining.

Massey's safety, productivity and measurement standards were developed from generations of coal mining experience and the commitment of members such as Chief Operating Officer Chris Adkins, Assistant Mine Foreman Jonathan Workman, Assistant Mine Foreman Matthew Dunbar and Section Electrician Matt Terry.

A with the people of Central Appalachia.

he energy 's here.

Improving our total environment. To deliver long-term success, Massey recognizes the importance of investing time and resources to improve the total environment of Central Appalachia.

Quality jobs. At Massey, we know that the only things more important than our coal resources are our human resources. We are continually investing in training our members to make them more skilled and productive.

Massey's benefits rank among the very best of any company in the United States. Massey built the West Virginia Family Wellness Center in Madison, West Virginia, to provide our members and their families access to the best healthcare in southern West Virginia. We also sponsor post-retirement pension and healthcare plans that allow our members to protect their financial future.

Most importantly, we focus every day to return our members home safely. Our safety record in 2006 was 13% better than the national industry average – Massey achieved a 2.77 Work Days Lost Incidence Rate per 200,000 hours worked, compared to a 3.19 average rate for the bituminous coal industry. We share our innovative safety technology and best practices freely with others in the industry to promote mining safety across Central Appalachia.

Responsible care for the environment. Massey Energy is committed to the protection and preservation of our land, air and water. Every year, Massey Energy plants approximately one million trees on reclaimed mining properties. We utilize what we consider the best and most environmentally-friendly methods available to return mining lands to a natural and sustainable state.

In 2006, Massey subsidiary Nicholas Energy Company earned the Excellence in Reforestation Award from the Appalachian Regional Reforestation Initiative. The award recognized Nicholas Energy for its innovative reclamation approach at its Wildcat Surface Mine.

Support for the local communities. As one of the region's largest employers, we also seek to improve the quality of life in the cities and towns where our members live. Our Partnership in Education program provides rural schools with financial assistance for educational materials. Since 1997, Massey has supported the Doctors for Our Communities program, which assists in educating and retaining primary care doctors in the Central Appalachian region. The Massey Spousal Groups have dedicated their time and resources to support those in need, from our service men and women to the elderly.

We also sponsor numerous events to benefit local communities. The annual Massey Energy Christmas Extravaganza provides toys to underprivileged children in Central Appalachia. Each year the event has grown, benefiting over 6,000 children in 2006.

Raymond Bradbury Safety Program.

The Raymond Bradbury Safety Program is an award-winning Massey initiative. The campaign coordinates safety reminders with competitions and rewards for safety achievements. It exemplifies our innovative approach to keeping our members focused on safety and working to make Massey mines accident-free.

1. Our modern coal operations rely on highly skilled professionals. 2. Support for local schools helps educate the next generation of Massey members. 3. Providing good jobs with quality benefits is one of Massey's greatest contributions. 4. The Massey Christmas Extravaganza benefits community children. 5. Dr. Amy Sayre, at the Massey Wellness Center, provides quality care for our members and their families. 6. Reclaimed mining properties provide habitats for wildlife and community recreation areas.

Vision to create tomorrow's opportunities.

The energy is here.

Dear Fellow Shareholders:

Coal is necessary today. At the start of every day, when I turn on the lights, I am relying on Central Appalachian coal to make them work. I am also relying on my neighbors, my friends and my fellow Massey members who work in the Central Appalachian coalfields to produce safely and efficiently the coal that our power plants require. Millions of other Americans are likewise relying on these men and women to do their jobs. In 2006, Central Appalachia produced 236 million tons of coal. This coal provided power for roughly 20% of the households and businesses in the United States. It was also used to manufacture 70 million tons of steel and to fuel many of our domestic industries. The coal that Massey members produce is not a luxury or a lifestyle consumer product. The coal that our members produce is fundamental to the modern way of life in America.

Coal will be crucial tomorrow. The United States consumes 25% of the world's oil production but has only 2% of the world's proved reserves of oil. As this math would predict, our country has become ever more dependent on imported oil. We are counting on the Middle East, Africa and South America to provide a dependable supply of fuel for the United States. Many of these oil-producing countries are politically unstable. In some cases, our dollars are funding regimes that are openly hostile toward the United States.

In the past decade, our country has also increasingly turned to natural gas in the belief that production would remain abundant and cheap. In much the same way as with oil, domestic reserves and production of natural gas have fallen, and the United States has looked overseas to import the natural gas it uses. Similar to oil, the United States consumes nearly 25% of the world's natural gas production but has only 3% of the world's proved natural gas reserves.

As more people in more countries adopt modern conveniences and compete for a larger share of the world's finite oil and gas resources, we at Massey believe the United States will eventually turn to coal for more of its energy. Fortunately, the United States has the world's largest reserves of coal – coal that can be converted to electricity, to motor fuel or to pipeline gas.

An open and rational debate about the long-term merits of carbon-based energy belongs on the nation's agenda. However, this discussion should not occur without addressing the near-term dangers of our current energy policy. The tangible costs of becoming more reliant on foreign energy supplies have been made apparent to all Americans. Our dependency on imported oil and gas is a national security crisis for the United States today. This very real and immediate threat is manageable with an appropriate national energy policy that utilizes our domestic coal reserves. It would be inappropriate to focus a national energy policy on climate change forecasts at the expense of American jobs and our national security interests.

Massey Energy can deliver. Since becoming Chairman in 1992, I have worked to ensure that Massey is well-positioned to generate returns over the long term in Central Appalachia. Achieving this required our management

Don L. Blankenship
Chairman, Chief Executive Officer and President

team not only to deliver results year over year, but also to make difficult decisions that would take a decade or more to prove out. Now those decisions have put us in a position to deliver value to our shareholders and deliver the energy that the United States will need in the coming decades.

Extensive reserves. With 2.2 billion tons of coal reserves in Central Appalachia, Massey may be the only major producer in the region that is capable of sustaining production in the next decade without moving into high-cost reserves or making large acquisitions.

Low legacy liabilities. Massey has avoided accumulating large legacy liabilities that have plagued much of the industry. Many of the legacy liabilities borne by the industry, such as multi-employer pension plans, don't appear on balance sheets and won't become apparent for years, but they are real and they will eventually come due.

Well-capitalized infrastructure. We have invested $1.2 billion in our infrastructure in just the past five years. These dollars were spent to make our mines and processing plants efficient and our equipment safe and productive. These investments will continue paying off for years to come.

Best practices. Our safety, productivity and measurement best practices have been developed from decades of coal mining experience in Central Appalachia. We are continuously enhancing these procedures and training our members in their methodology. This is one reason we have been able to incorporate more than 4,000 new hires in the past two years and still achieve above-average safety and productivity rates.

Looking to 2007. We have many reasons to be optimistic about 2007. Our turnover rate has improved significantly so far this year, and we are seeing higher productivity from our mines as a result. Our new dragline operation is in full production, expanding our low-cost surface mining capabilities. Our Aracoma mine that was idle and recovering from a mine fire this time last year, has returned to production. Our new Kepler mine will soon be producing coal, giving us access to 44 million tons of low volatile, high-quality metallurgical coal. Our new Mammoth 2-Gas seam mine, with strategic river access, will begin production of high-quality steam coal this summer.

I personally have several goals for the upcoming year. First, to improve further on our already excellent safety record. Second, to reduce our cash costs from the unacceptably high levels we experienced in 2006. Third, to be disciplined users of capital, deploying our free cash flow to strengthen our balance sheet and to return value to our shareholders if we don't find attractive investment opportunities. Finally, for Massey to end 2007 in an even stronger strategic position than it is today.

I would like to thank our customers, communities, members and shareholders for their continued support as we work together for future success.

Don L Blankenship

Don L. Blankenship
Chairman, Chief Executive Officer and President

Selected financial data

(In millions, except per share, per ton and number of employees amounts)	Year Ended December 31, 2006	2005	2004	2003	2002
Consolidated Statement of Income Data					
Produced coal revenue	**$ 1,902.3**	$ 1,777.7	$ 1,456.7	$ 1,262.1	$ 1,318.9
Total revenue	**2,219.9**	2,204.3	1,766.6	1,571.4	1,630.1
Income (Loss) before interest and income taxes	**111.0**	(20.9)	46.2	(17.5)	(26.7)
Income (Loss) before cumulative effect of accounting change	**41.6**	(101.6)	13.9	(32.3)	(32.6)
Net income (loss)	**41.0**	(101.6)	13.9	(40.2)	(32.6)
Income (Loss) per share – Basic					
Income (Loss) before cumulative effect of accounting change	**$ 0.51**	$ (1.33)	$ 0.18	$ (0.43)	$ (0.44)
Net income (loss)	**$ 0.50**	$ (1.33)	$ 0.18	$ (0.54)	$ (0.44)
Income (Loss) per share – Diluted					
Income (Loss) before cumulative effect of accounting change	**$ 0.51**	$ (1.33)	$ 0.18	$ (0.43)	$ (0.44)
Net income (loss)	**$ 0.50**	$ (1.33)	$ 0.18	$ (0.54)	$ (0.44)
Dividends declared per share	**$ 0.16**	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Consolidated Balance Sheet Data					
Working capital (deficit)	**$ 445.2**	$ 670.8	$ 458.4	$ 443.2	$ (59.7)
Total assets	**2,740.7**	2,986.5	2,650.9	2,376.7	2,241.4
Long-term debt	**1,102.3**	1,102.6	900.2	784.3	286.0
Shareholders' equity	**697.3**	841.0	776.9	459.0	808.2
Other Data					
EBIT	**$ 111.0**	$ (20.9)	$ 46.2	$ (17.5)	$ (26.7)
EBITDA	**$ 341.5**	$ 213.6	$ 270.8	$ 179.0	$ 181.0
Average cash cost per ton sold	**$ 42.33**	$ 35.62	$ 30.50	$ 28.23	$ 28.64
Produced coal revenue per ton sold	**$ 48.71**	$ 42.02	$ 36.02	$ 30.79	$ 31.30
Capital expenditures	**$ 298.1**	$ 346.6	$ 347.2	$ 164.4	$ 155.1
Produced tons sold	**39.1**	42.3	40.4	41.0	42.1
Tons produced	**38.6**	43.1	42.0	41.0	43.9
Number of employees	**5,517**	5,709	5,034	4,428	4,552

All financial data should be read in conjunction with the audited Consolidated Financial Statements and Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the period ended December 31, 2006, filed with the Securities and Exchange Commission on March 1, 2007, provided herein.

For further description of the shares used to calculate basic and diluted pro forma earnings per share and for the calculation of EBITDA and average cash cost per ton sold, please refer to our Annual Report on Form 10-K, provided herein.

Consolidated balance sheets

(In thousands, except per share amounts)	At December 31, 2006	2005
Assets		
Current Assets		
Cash and cash equivalents	**$ 239,245**	$ 319,418
Trade and other accounts receivable, less allowance of $576 and $2,063, respectively	**197,105**	152,564
Inventories	**191,056**	345,654
Deferred income taxes	**-**	5,182
Income taxes receivable	**-**	18,054
Other current assets	**172,322**	203,685
Total current assets	**799,728**	1,044,557
Net Property, Plant and Equipment	**1,776,781**	1,715,936
Other Noncurrent Assets		
Pension assets	**34,974**	78,702
Other noncurrent assets	**129,213**	147,327
Total other noncurrent assets	**164,187**	226,029
Total assets	**$2,740,696**	$2,986,522
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable, principally trade and bank overdrafts	**$ 117,157**	$ 162,789
Short-term debt	**2,583**	10,680
Payroll and employee benefits	**40,380**	40,914
Income taxes payable	**19,412**	–
Other current liabilities	**175,005**	159,347
Total current liabilities	**354,537**	373,730
Noncurrent Liabilities		
Long-term debt	**1,102,324**	1,102,582
Deferred income taxes	**116,690**	218,801
Other noncurrent liabilities	**469,854**	450,425
Total noncurrent liabilities	**1,688,868**	1,771,808
Total liabilities	**2,043,405**	2,145,538
Shareholders' Equity		
Capital Stock		
Preferred – authorized 20,000,000 shares without par value; none issued	**-**	–
Common – authorized 150,000,000 shares of $0.625 par value; issued 82,365,259 and 81,939,989 shares, respectively	**51,458**	51,213
Treasury stock, 1,299,000 shares at cost	**(49,995)**	–
Additional capital	**220,650**	215,749
Unamortized executive stock plan expense	**-**	(7,130)
Retained earnings	**515,894**	581,621
Accumulated other comprehensive loss	**(40,716)**	(469)
Total shareholders' equity	**697,291**	840,984
Total liabilities and shareholders' equity	**$2,740,696**	$2,986,522

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Consolidated statements of income

(In thousands, except per share amounts)	Year Ended December 31, 2006	2005	2004
Revenues			
Produced coal revenue	**$1,902,259**	$1,777,724	$1,456,684
Freight and handling revenue	**156,531**	150,898	148,795
Purchased coal revenue	**70,636**	132,320	104,955
Other revenue	**90,428**	143,316	56,210
Total revenues	**2,219,854**	2,204,258	1,766,644
Costs and Expenses			
Cost of produced coal revenue	**1,599,092**	1,438,494	1,175,900
Freight and handling costs	**156,531**	150,898	148,795
Cost of purchased coal revenue	**62,613**	112,600	104,109
Depreciation, depletion and amortization, applicable to:			
Cost of produced coal revenue	**227,279**	230,545	220,135
Selling, general and administrative	**3,259**	4,020	4,482
Selling, general and administrative	**53,834**	68,254	57,525
Other expense	**6,240**	8,018	9,509
Loss on capital restructuring	**-**	212,378	-
Total costs and expenses	**2,108,848**	2,225,207	1,720,455
Income (Loss) before interest and taxes	**111,006**	(20,949)	46,189
Interest income	**20,094**	12,603	8,828
Interest expense	**(86,076)**	(67,064)	(60,660)
Income (Loss) before taxes	**45,024**	(75,410)	(5,643)
Income tax (expense) benefit	**(3,408)**	(26,228)	19,495
Income (Loss) before cumulative effect of accounting change	**41,616**	(101,638)	13,852
Cumulative effect of accounting change, net of tax	**(639)**	-	-
Net income (loss)	**$ 40,977**	$ (101,638)	$ 13,852
Income (Loss) per share – Basic			
Income (Loss) before cumulative effect of accounting change	**$ 0.51**	$ (1.33)	$ 0.18
Cumulative effect of accounting change	**(0.01)**	-	-
Net income (loss)	**$ 0.50**	$ (1.33)	$ 0.18
Income (Loss) per share – Diluted			
Income (Loss) before cumulative effect of accounting change	**$ 0.51**	$ (1.33)	$ 0.18
Cumulative effect of accounting change	**(0.01)**	-	-
Net income (loss)	**$ 0.50**	$ (1.33)	$ 0.18
Shares used to calculate income per share			
Basic	**80,847**	76,390	75,262
Diluted	**81,386**	76,390	76,450

All financial data should be read in conjunction with the audited Consolidated Financial Statements and Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 1, 2007, provided herein.

Consolidated statements of cash flows

(In thousands)	2006	2005	2004
	Year Ended December 31,		
Cash Flows from Operating Activities			
Net income (loss)	**$ 40,977**	$ (101,638)	$ 13,852
Adjustments to reconcile Net income (loss) to Cash provided by operating activities:			
Cumulative effect of accounting change	**639**	–	–
Depreciation, depletion and amortization	**230,538**	234,565	224,617
Stock-based compensation expense	**7,350**	–	–
Deferred income taxes	**(17,381)**	23,259	1,181
Gain on disposal of assets	**(46,557)**	(63,879)	(22,789)
Gain on reserve exchange	–	(38,198)	–
Loss on repurchase of senior notes	–	669	1,279
Loss on debt restructuring	–	212,378	–
Writeoff of deferred financing costs	–	6,648	–
Accretion of asset retirement obligation	**10,166**	10,156	8,743
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	**(43,456)**	13,559	(19,465)
Increase in inventories	**(8,070)**	(85,869)	(53,169)
Decrease (increase) in other current assets	**24,573**	(4,695)	26,582
Decrease (increase) in pension and other assets	**1,165**	(6,830)	(17,714)
(Decrease) increase in accounts payable and bank overdrafts	**(45,632)**	26,917	25,551
Increase (decrease) in accrued income taxes	**42,638**	15,320	(20,635)
Increase in other accrued liabilities	**17,046**	19,502	35,271
Increase in other noncurrent liabilities	**4,712**	12,140	29,446
Asset retirement obligation payments	**(4,205)**	(3,858)	(6,090)
Cash provided by operating activities	**214,503**	270,146	226,660
Cash Flows from Investing Activities			
Capital expenditures	**(298,132)**	(346,578)	(347,152)
Proceeds from sale of assets	**51,467**	73,542	57,731
Cash utilized by investing activities	**(246,665)**	(273,036)	(289,421)
Cash Flows from Financing Activities			
Repurchase of senior notes	–	(19,890)	(70,799)
Stock repurchase	**(49,995)**	–	–
Repayments of capital lease obligations	**(10,214)**	(19,370)	(17,770)
Proceeds from issuance of 6.875% senior notes	–	742,847	–
Proceeds from issuance of convertible senior notes	–	–	170,275
Debt restructuring	–	(562,608)	–
Early termination of fair value hedge	–	(7,922)	–
Proceeds from sale-leaseback transactions	**21,819**	71,697	15,000
Cash dividends paid	**(12,814)**	(12,208)	(12,024)
Proceeds from stock options exercised	**2,142**	7,231	11,857
Income tax benefit from stock option exercises	**1,051**	–	–
Cash (utilized) provided by financing activities	**(48,011)**	199,777	96,539
(Decrease) increase in cash and cash equivalents	**(80,173)**	196,887	33,778
Cash and cash equivalents at beginning of period	**319,418**	122,531	88,753
Cash and cash equivalents at end of period	**$ 239,245**	$ 319,418	$ 122,531
Supplemental Cash Flow Information			
Cash paid during the period for income taxes	**$ 157**	$ 9,205	$ 572

All financial data should be read in conjunction with the audited Consolidated Financial Statements and Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 1, 2007, provided herein.

Directors

Don L. Blankenship, 57
Mr. Blankenship has been Chairman, Chief Executive Officer and President of the Company since 2000 and Chairman, Chief Executive Officer and President of A.T. Massey Coal Company, Inc. since 1992. Mr. Blankenship joined a Massey subsidiary, Rawl Sales & Processing Co., in 1982. Mr. Blankenship also serves as a director of the National Mining Association and the U.S. Chamber of Commerce. [1]

James B. Crawford, 64
Mr. Crawford is currently serving as a consultant for Evan Energy Investments, LC and as Chairman of InterAmerican Coal Holding N.V., an Evan Energy investment. He is the former Chairman and Chief Executive Officer of James River Coal Company, from its founding in 1988 to 2003. Mr. Crawford is Chair Emeritus and a member of the Board of Trustees of Colby College. [2,4,5]

General Robert H. Foglesong (ret.), 61
General Foglesong has served as President of Mississippi State University since 2006. Previously he was a four-star general in the U.S. Air Force. Gen. Foglesong serves as a director of Michael Baker Corporation, a leading professional services firm, and also serves as President and Executive Director of the Appalachian Leadership and Education Foundation. [3,4,5]

E. Gordon Gee, 63
Mr. Gee has served as Chancellor of Vanderbilt University since 2000. Prior to that, he was President of Brown University (1998–2000) and President of The Ohio State University (1990–1998). He also serves as a director of Dollar General Corporation, Gaylord Entertainment Company, Hasbro, Inc. and Limited Brands, Inc. [1,2,4,5]

William R. Grant, 82
Mr. Grant is the co-founder of Galen Associates, a venture capital company. Mr Grant also serves as a director of Advanced Medical Optics, Inc., Quest Diagnostics, Inc. and Vasogen, Inc. [1,2,3,4]

Admiral Bobby R. Inman (ret.), 75
Retired from the U.S. Navy as a four-star admiral, Admiral Inman currently serves as a professor at the LBJ School of Public Affairs at the University of Texas. He previously served as Director of the National Security Agency and Deputy Director of the Central Intelligence Agency. [1,3,4]

Daniel S. Loeb, 45
Mr. Loeb is Chief Executive Officer of Third Point LLC, an investment management firm based in New York that he founded in 1995. He is also on the Board of American Restaurant Group and Pogo Producing Company. [3,4]

Dan R. Moore, 66
Mr. Moore is the Chairman of Moore Group, Inc. He is the former Chairman of the Board and President of Matewan BancShares, which was sold to BB&T Corporation in 1999. He serves as a member of the West Virginia University Foundation Board. [1,2,4,5]

Dr. Martha R. Seger, 75
Dr. Seger has been an unpaid visiting professor at a number of universities, most recently at Arizona State University. She is a former member of the Board of Governors of the Federal Reserve System and previously served on numerous publicly traded company boards. [1,2,3,4]

Todd Q. Swanson, 32
Mr. Swanson joined Third Point LLC in September 2005 after receiving his M.B.A. from the Graduate School of Business at Stanford University. Prior to that, he worked for Thomas Cressey Equity Partners, a private equity firm based in Chicago.[2,4]

(1) Executive Committee, Don L. Blankenship, Chairman; (2) Audit Committee, Dan R. Moore, Chairman; (3) Compensation Committee, Bobby R. Inman, Chairman; (4) Governance and Nominating Committee, Martha R. Seger, Chair; (5) Safety, Environmental and Public Policy Committee, E. Gordon Gee, Chairman

Officers

Don L. Blankenship
Chairman, Chief Executive Officer and President (1982)

Baxter F. Phillips, Jr.
Executive Vice President and Chief Administrative Officer (1981)

J. Christopher Adkins
Senior Vice President and Chief Operating Officer (1985)

H. Drexel Short, Jr.
Senior Vice President – Group Operations (1981)

Michael K. Snelling
Vice President – Surface Operations, Massey Coal Services, Inc. (2000)

Michael D. Bauersachs
Vice President – Planning (1998)

Thomas J. Dostart
Vice President, General Counsel and Assistant Secretary (2003)

Richard R. Grinnan
Vice President and Corporate Secretary (2004)

Jeffrey M. Jarosinski
Vice President – Finance and Chief Compliance Officer (1988)

John M. Poma
Vice President – Human Resources (1996)

Eric B. Tolbert
Vice President and Chief Financial Officer (1992)

Roger T. Williams
Vice President – Sales (2005)

David W. Owings
Corporate Controller (2001)

Years in parentheses indicate the year each officer joined the Company.

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

FORM 10-K

(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, 2006

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 No. 1-7775

MASSEY ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware	95-0740960
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
4 North 4th Street, Richmond, Virginia	23219
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (804) 788-1800

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.625 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 or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (Check One):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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 Common Stock held by non-affiliates of the registrant on June 30, 2006, was $2,906,625,168 based on the last sales price reported that date on the New York Stock Exchange of $36.00 per share. In determining this figure, the Registrant has assumed that all of its directors and executive officers are affiliates. Such assumptions should not be deemed to be conclusive for any other purpose.

Common Stock, $0.625 par value, outstanding as of February 15, 2007 — 81,068,790 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant's definitive proxy statement for the 2007 annual meeting of shareholders, which proxy statement will be filed no later than 120 days after the close of the registrant's fiscal year ended December 31, 2006.

Forward Looking Statements

From time to time, Massey Energy Company, which includes its direct and wholly owned subsidiary, A.T. Massey Coal Company, Inc, and its direct and indirect wholly owned subsidiaries ("we," "our," "us"), makes certain comments and disclosures in reports, including this report, or through statements made by our officers that may be forward-looking in nature. Examples include statements related to our future outlook, anticipated capital expenditures, projected cash flows and borrowings, and sources of funding. We caution readers that forward-looking statements, including disclosures that use words such as "believe," "anticipate," "expect," "estimate," "intend," "plan," "project" and similar statements are subject to certain risks, trends and uncertainties that could cause actual cash flows, results of operations, financial condition, cost reductions, acquisitions, dispositions, financing transactions, operations, expansion, consolidation and other events to differ materially from the expectations expressed or implied in such forward-looking statements. Any forward-looking statements are also subject to a number of assumptions regarding, among other things, future economic, competitive and market conditions. These assumptions are based on facts and conditions, as they exist at the time such statements are made as well as predictions as to future facts and conditions, the accurate prediction of which may be difficult and involve the assessment of circumstances and events beyond our control. We disclaim any obligation to update these forward-looking statements unless required by securities law, and we caution the reader not to rely on them unduly.

We have based any forward-looking statements we have made on our current expectations and assumptions about future events and circumstances that are subject to risks, uncertainties and contingencies that could cause results to differ materially from those discussed in the forward-looking statements, including, but not limited to:

(i) our cash flows, results of operation or financial condition;

(ii) the consummation of acquisition, disposition or financing transactions and the effect thereof on our business;

(iii) governmental policies and regulatory actions affecting the coal industry;

(iv) legal and administrative proceedings, settlements, investigations and claims and the availability of insurance coverage related thereto;

(v) weather conditions or catastrophic weather-related damage;

(vi) our ability to produce coal to meet market expectations and customer requirements;

(vii) our ability to obtain and renew permits necessary for our existing and planned operations in a timely manner;

(viii) the availability of transportation for our produced coal;

(ix) the expansion of our mining capacity;

(x) our ability to manage production costs;

(xi) the market demand for coal, electricity and steel;

(xii) the cost and perceived benefits of alternative sources of energy such as natural gas and nuclear energy;

(xiii) competition among coal and other energy producers, at home and abroad;

(xiv) our ability to timely obtain necessary supplies and equipment;

(xv) our reliance upon and relationship with our customers and suppliers;

(xvi) the creditworthiness of our customers and suppliers;

(xvii) our ability to attract, train and retain a skilled workforce to meet replacement or expansion needs;

(xviii) our assumptions and projections concerning economically recoverable coal reserve estimates;

(xix) future economic or capital market conditions;

(xx) the availability and costs of credit, surety bonds and letters of credit that we require;

(xxi) our assumptions and projections regarding pension and other post-retirement benefit liabilities; and

(xxii) the successful implementation of our strategic plans and objectives.

Any forward-looking statements should be considered in context with the various disclosures made by us about our businesses, including without limitation the risk factors more specifically described below in Item 1A. Risk Factors of this Annual Report on Form 10-K.

2006 ANNUAL REPORT ON FORM 10-K

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Annual Shareholders Meeting

Our 2007 Annual Meeting of Shareholders will be held at 9:00 a.m. EDT on Tuesday, May 22, 2007 at the Four Seasons Hotel, 57 East 57th Street, New York, New York 10022.

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Part I

Because certain terms used in the coal industry may be unfamiliar to many investors, we have provided a Glossary of Selected Terms beginning on page 18 at the end of Item 1. Business.

Item 1. Business

We produce, process and sell bituminous coal of steam and metallurgical grades, primarily of a low sulfur content, through our 22 processing and shipping centers, called "Resource Groups," many of which receive coal from multiple coal mines. At January 31, 2007, we operated 33 underground mines (three of which employ both room and pillar and longwall mining) and 11 surface mines (with seven highwall miners in operation) in West Virginia, Kentucky and Virginia. The number of mines that we operate may vary from time to time depending on a number of factors, including the existing demand for and price of coal, exhaustion of economically recoverable reserves and availability of experienced labor. Utility and industrial clients primarily purchase our steam coal as fuel for power plants. Our metallurgical coal is used primarily to make coke for use in the manufacture of steel. As measured by 2006 revenue, Energy Ventures Analysis, Inc. ("EVA") ranks us as the fourth largest coal company in the United States ("U.S."), and the largest in the Central Appalachian region. The Central Appalachian region is comprised of eastern Kentucky, Virginia, and southern West Virginia.

A.T. Massey was originally incorporated in Richmond, Virginia in 1920 as a coal brokering business. In the late 1940s, A.T. Massey expanded its business to include coal mining and processing. In 1974, St. Joe Minerals acquired a majority interest in A.T. Massey. In 1981, St. Joe Minerals was acquired by Fluor Corporation. A.T. Massey was wholly owned by Fluor Corporation from 1987 until November 30, 2000, when we completed a reverse spin-off (the "Spin-Off"), which divided it into the spun-off corporation, "new" Fluor Corporation ("New Fluor"), and Fluor Corporation, subsequently renamed Massey Energy Company, which retained our coal-related businesses.

During 2006, our produced coal revenues increased by 7% to $1.9 billion on produced coal sales of 39.1 million tons. Exports decreased 20% to 4.2 million tons. In 2006, we recorded net income of $41.0 million or $0.50 per diluted share. Net income in 2006 included pre-tax gains totaling approximately $30 million ($19 million after-tax or $0.24 per diluted share) related to the sale of our Falcon reserves. The sale was to a privately held coal company and consisted of approximately 5.5 million tons of coal reserves.

In an effort to capitalize on increases in coal prices in recent years due primarily to increased market demand, we committed to building capacity, mainly by expanding our lower cost surface mine operations and purchasing additional surface and underground equipment. In August 2006, we completed the renovation of, and put into production, our first dragline at our Progress resource group's Twilight Surface Mine. Total capital spending for 2006 was $298.1 million, including approximately $25.3 million in operating lease buyouts. Our total workforce was 5,517 employees at the end of 2006.

During January 2006, our Logan County resource group's Aracoma longwall mine experienced a fire that began on a conveyor belt. Although certain mining equipment was lost due to the fire, the longwall and mining equipment at the working faces were not damaged. The Aracoma mine returned to operational status in July 2006. In November 2006, we discontinued production from our Rockhouse longwall, which was located at our Sidney resource group.

As part of an overall strategic review of our operations, from late December 2006 to early January 2007, we idled one deep mine and four surface mines at our Coalgood, Logan County and Martin County resource groups. The mines idled produced 1.9 million tons in 2006.

In June 2006, in response to multiple fatalities within the mining industry earlier that year, Congress passed and President Bush signed the Mine Improvement and New Emergency Response Act of 2006 ("MINER Act"), which among other things requires mine-specific emergency response plans, enhanced communication systems, and more available mine rescue teams, as well as larger penalties by the Federal Mine Safety and Health Administration ("MSHA") for noncompliance by mine operators. In December 2006, MSHA similarly passed its final rule on Emergency Mine Evacuation, which includes requirements for increased availability and storage of self-contained self-rescue devices ("SCSRs"); improved emergency evacuation drills and SCSR training; and the installation and maintenance of lifelines in underground coal mines. Coal producing states, including West Virginia and Kentucky, passed similar legislation in 2006. While the full cost of compliance remains unknown, we spent over $3 million in 2006 and estimate that we will spend a total of $20 million to $25 million over two to three years to fully comply with these laws. These costs were capitalized in Net Property, Plant and Equipment for 2006.

On April 24, 2006, our Board of Directors amended our $500 million share repurchase program of our common stock, $0.625 par value ("Common Stock"), authorized in the fourth quarter of 2005, to allow share repurchases of up to $50 million to commence using cash currently on hand. Share repurchases of $50 million, using cash currently on hand, were completed on June 8, 2006, with the purchase of 1.3 million shares at an average price of $38.47. All shares repurchased under the program were recorded as Treasury stock.

Industry Overview

Coal is the second most widely used form of energy used in the U.S. each day, accounting for one-fourth of the nation's total energy consumption, according to the BP Statistical Review of World Energy ("BP"), June 2006. It is the source of 50% of the electricity generated nationwide, as reported by EVA.

The U.S. is the second largest coal producer in the world, exceeded only by China. Other leading coal producers include India, Australia, South Africa, Russia and Indonesia. The U.S. has the largest coal reserves in the world, with over 230 years supply at current production rates. U.S. coal reserves are more plentiful than oil or natural gas, with coal representing approximately 68% of the nation's fossil fuel reserves according to EVA, based on a comparison of the total probable heat value (British thermal units per pound) of the demonstrated coal reserve tonnage to the heat value of other fossil fuel energy resources using information prepared by the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy.

U.S. coal production has more than doubled over the last 40 years. In 2005, total U.S. coal production, as estimated by the EIA, was 1.1 billion tons. The primary producing regions by tons were the Powder River Basin (38%), Central Appalachia (21%), West (other than the Powder River Basin) (14%), Midwest (13%), Northern Appalachia (12%), and all other (2%). All of our coal production comes from the Central Appalachian region. The EIA estimated that approximately 67% of U.S. coal was produced by surface mining methods. The remaining 33% was produced by underground mining methods, which include room and pillar mining and longwall mining (more fully described in Item 1. Business, under the heading "Mining Methods").

Coal is used in the U.S. by utilities to generate electricity, by steel companies to make steel products, and by a variety of industrial users to produce heat and to power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Significant quantities of coal are also exported from both East and West Coast terminals. The breakdown of 2005 U.S. coal consumption, as estimated by the EIA, is as follows:

End Use	% of Total
Electric Power	92%
Other Industrial	5%
Coke	2%
Residential and Commercial	1%
Total	100%

Coal has long been favored as an electricity generating fuel because of its basic economic advantage. The largest cost component in electricity generation is fuel. This fuel cost is typically lower for coal than competing fuels such as oil and natural gas on a Btu-comparable basis. Platts, which provides global commodity news and information, estimated the average total production costs of electricity, using coal and competing generation alternatives in 2006 as follows:

Electricity Generation Source	Cost per million Kilowatt Hours
Oil	$ 14.69
Natural Gas	$ 7.97
Coal	$ 2.19
Nuclear	$ 1.84

There are factors other than fuel cost that influence each utility's choice of electricity generation mode, including facility construction cost, access to fuel transportation infrastructure, environmental restrictions, and other factors. The breakdown of U.S. electricity generation by fuel source in 2006, as estimated by Platts, is as follows:

Electricity Generation Source	% of Total Electricity Generation
Coal	50%
Nuclear	20%
Natural Gas	20%
Oil	2%
Other (hydroelectric, solar, wind, etc.)	8%
Total	100%

Demand for electricity has historically been driven by U.S. economic growth. Because coal-fired generation is used in most cases to meet base load requirements, coal consumption has generally grown at the pace of electricity demand growth.

According to the World Coal Institute ("WCI"), the U.S. ranks seventh among worldwide exporters of coal. Australia is the largest exporter, with other major exporters including Indonesia, China, South Africa, Russia, Columbia and Canada. According to the EIA, U.S. exports, which had decreased by over 61% between 1992 and 2002 as a result of increased international competition and the U.S. dollar's historic strength in comparison to foreign currencies, increased by 26% from 2002 to 2005. The usage breakdown for 2006 U.S. exports of 48 million tons was 44% for electricity generation and 56% for steel making. In 2006, U.S. coal exports were shipped to more than 30 countries. The largest purchaser of U.S. exported utility coal in 2006 continued to be Canada, which took 11.5 million tons or 70% of total utility coal exports. The largest purchasers of U.S. exported metallurgical coal were Canada, which imported 3.3 million tons, or 16%, and Brazil, which imported 3.2 million tons, or 15%. Utility coal exports to Ontario, Canada, however, may be negatively impacted as the government makes progress toward shutting down all of Ontario's coal plants, which accounted for approximately 25% of the province's generating capacity in 2004. The first of five coal-fired plants was closed in April of 2005 and the remainder are scheduled for closure starting in 2007 and ending in 2009 as replacement resources become available. However, Ontario may defer closures of their coal fired plants in recognition of the costs and environmental impacts associated with alternative power sources.

Depending on the relative strength of the U.S. dollar versus currencies in other coal producing regions of the world, U.S. producers may export more or less coal into foreign countries as they compete on price with other foreign coal producing sources. Additionally, the domestic coal market may be impacted due to the relative strength of the U.S. dollar to other currencies, as foreign sources could be cost-advantaged based on a coal producing region's relative currency position. In 2006, according to the Argus Media Inc. ("Argus"), coal imported into the U.S. was 36.2 million tons. Columbia continued to dominate as the source for coal imported into the U.S., accounting for 70% of imports, followed by Venezuela and Indonesia. During 2006, the U.S. dollar weakened somewhat, making imported coal less competitive with U.S. produced coal, and positively impacting the competitiveness of U.S. exports in some overseas markets.

From 2003 to early 2006, a significant demand/supply imbalance of coal developed, resulting in record high prices for coal producers in the U.S. Increased worldwide demand was primarily driven by significantly higher prices for oil and natural gas and economic expansion, particularly in China and elsewhere in Asia. At the same time, infrastructure and regulatory limitations in China contributed to a tightening of worldwide coal supply, affecting global prices of coal. China's growth caused an increase in worldwide demand for raw materials and a disruption of expected coal exports to Japan, Korea, India and other countries. During 2006, the market prices of steam coal gradually dropped as a warm winter and mild summer weather in the U.S. allowed utilities to rebuild their stockpiles. Demand and prices for oil and natural gas also dropped during this period, as natural gas injections reached an all-time high in the fall of 2006.

Metallurgical grade coal is distinguished by special quality characteristics that include high carbon content, volatile matter, low expansion pressure, low sulfur content, and various other chemical attributes. High vol met coal is also high in heat content (as measured in Btus), and therefore is desirable to utilities as fuel for electricity generation. Consequently, high vol met coal producers have the ongoing opportunity to select the market that provides maximum revenue. The premium price offered by steel makers for the metallurgical quality attributes is typically higher than the price offered by utility coal buyers that value only the heat content. The primary concentration of U.S. metallurgical coal reserves is located in the Central Appalachian region. EVA estimates that the Central Appalachian region supplied 89% of domestic metallurgical coal and 73% of U.S. exported metallurgical coal during 2006.

For utility coal buyers, the primary goal is to maximize heat content, with other specifications like ash content, sulfur content, and size varying considerably among different customers. Low sulfur coals such as those produced in the western U.S. and in Central Appalachia, generally demand a higher price due to restrictions on sulfur emissions imposed by the Clean Air Act and the significant increase in SO_2 allowance prices that occurred in recent years when the demand for all specifications of coal increased. SO_2 allowances permit utilities to emit a higher level of SO_2 than otherwise required under the Clean Air Act regulations. The demand and premium price for low sulfur coal is expected to diminish as more utilities install scrubbers at their coal-fired plants. Industrial users of coal typically purchase high Btu products with the same type of quality focus as utility coal buyers. Because most industrial coal consumers use considerably less tonnage than electric generating stations, they typically prefer to purchase coal that is screened and sized to specifications that streamline coal handling processes. Due to the more stringent size and quality specifications, industrial customers often pay a 10% to 15% premium above utility coal pricing (on comparable quality). The largest regional supplier to the industrial market sector has historically been Central Appalachia, which, according to EVA, supplied approximately 34% of all U.S. industrial coal demand in 2005.

Coal shipped for North American consumption is typically sold at the mine loading facility with transportation costs being borne by the purchaser. Offshore export shipments are normally sold at the ship-loading terminal, with the purchaser paying the ocean freight. According to the National Mining Association ("NMA"), approximately two-thirds of U.S. coal production in recent years was shipped via railroads. Final delivery to consumers often involves more than one transportation mode. A significant portion of U.S. production is delivered to customers via barges on the inland waterway system and ships loaded at Great Lakes ports.

We operate solely in the Central Appalachian region, which includes coal production from eastern Kentucky, southern West Virginia, western Virginia and eastern Tennessee. This region is the principal source of low sulfur bituminous coal in the U.S., used for power generation, metallurgical coke production and industrial boilers. Central Appalachian coal accounted for 22% of 2005 U.S. coal production according to EVA.

Neither we nor any of our subsidiaries are affiliated with or have any investment in the Argus, BP, EIA, EVA, Platts or WCI. We are a member of the NMA. All information provided by Platts is from *Platt's Energy Advantage, 2007.*

Mining Methods

We produce coal using four distinct mining methods: underground room and pillar, underground longwall, surface and highwall mining, which are explained as follows.

In the underground room and pillar method of mining, continuous mining machines cut three to nine entries into the coal bed and connect them by driving crosscuts, leaving a series of rectangular pillars, or columns of coal, to help support the mine roof and control the flow of air. Generally, openings are driven 20 feet wide and the pillars are 40 to 100 feet wide. As mining advances, a grid-like pattern of entries and pillars is formed. When mining advances to the end of a panel, retreat mining may begin. In retreat mining, as much coal as is feasible is mined from the pillars that were created in advancing the panel, allowing the roof to fall upon retreat. When retreat mining is completed to the mouth of the panel, the mined panel is abandoned.

In longwall mining (which is a type of underground mining), a shearer (cutting head) moves back and forth across a panel of coal typically about 1,000 feet in width, cutting a slice approximately 3.5 feet deep. The cut coal falls onto a flexible conveyor for removal. Longwall mining is performed under hydraulic roof supports (shields) that are advanced as the seam is cut. The roof in the mined out areas falls as the shields advance.

Surface mining is used to extract coal deposits found close to the surface. This method involves removal of overburden (earth and rock covering coal) with heavy earth moving equipment, including large shovels and draglines, and explosives, followed by extraction of coal from coal seams. After extraction of coal, disturbed parcels of land are reclaimed by replacing overburden and reestablishing vegetation and plant life.

Highwall mining is used in connection with surface mining. A highwall mining system consists of a remotely controlled continuous mining machine, which extracts coal and conveys it via augers or belt conveyors to the portal. The cut is typically a rectangular, horizontal opening in the highwall (the unexcavated face of exposed overburden and coal in a surface mine) 11-feet wide and reaching depths of up to 1,000 feet. Multiple, parallel openings are driven into the highwall, separated by narrow pillars that extend the full depth of the hole.

Use of continuous mining machines in the room and pillar method of underground mining represented approximately 40% of our 2006 coal production. Production from underground longwall mining operations constituted approximately 7% of our 2006 production. Surface mining represented approximately 46% of our 2006 coal production. Surface mines also use highwall mining systems to produce coal from high overburden areas. Highwall mining represented approximately 7% of our 2006 coal production.

Mining Operations

We currently have 22 distinct Resource Groups, including sixteen in West Virginia, five in Kentucky and one in Virginia. These complexes blend, process and ship coal that is produced from one or more mines, with a single complex handling the coal production of as many as seven distinct underground or surface mines. Our mines have been developed at strategic locations in close proximity to our preparation plants and rail shipping facilities. Coal is transported from the mining complexes to customers by means of railroad cars, trucks or barges, with rail shipments representing approximately 91% of 2006 coal shipments.

The following table provides key operational information on our Resource Groups in 2006.

Resource Group Name	Location (County)	2006 Production (1)	2006 Shipments (2)	Year Established or Acquired
		(Thousands of Tons)		
West Virgina Resource Groups				
Black Castle	Boone	3,127	1,741	1987
Delbarton	Mingo	355	904	1999
Edwight	Raleigh	1,701	-	2003
Elk Run	Boone	1,847	2,212	1978
Endurance	Boone	1,152	747	2001
Green Valley	Nicholas	782	810	1996
Independence	Boone	1,935	3,755	1994
Kepler	Wyoming	-	-	2006
Logan County	Logan	3,944	3,512	1998
Mammoth	Kanawha	1,498	2,089	2004
Marfork	Raleigh	3,870	6,340	1993
Nicholas Energy	Nicholas	3,196	3,127	1997
Progress	Boone	4,493	3,427	1998
Rawl	Mingo	1,368	287	1974
Republic Energy	Raleigh	1,047	645	2004
Stirrat	Logan	1,163	1,393	1993
Kentucky Resource Groups				
Coalgood Energy	Harlan	237	226	2005
Long Fork	Pike	-	1,966	1991
Martin County	Martin	778	788	1969
New Ridge	Pike	-	1,360	1992
Sidney	Pike	5,337	2,949	1984
Virginia Resource Group				
Knox Creek	Tazewell	781	773	1997
Total		38,611	39,051	

(1) For purposes of this table, coal production has been allocated to the Resource Group where the coal is mined, rather than the Resource Group where the coal is processed and shipped. Production amounts above represent coal extracted from the ground.

(2) For purposes of this table, coal shipments have been allocated to the Resource Group from where the coal is processed and shipped, rather than the Resource Group where the coal is mined.

The following descriptions of the Resource Groups are current as of January 31, 2007.

West Virginia Resource Groups

Black Castle. The Black Castle complex includes a large surface mine, a highwall miner, the Homer III direct-ship loadout, a stoker plant, and the Omar preparation plant. Some of the surface mine coal is trucked to the stoker plant where the coal is crushed and screened. The stoker product is trucked to river docks for barge delivery or trucked directly to customers. A portion of the coal is transported to the Omar plant via an underground belt conveyor system, where it is crushed and shipped to customers or, if the coal needs processing, it is belted to the preparation plant at the Independence Resource Group for processing and shipment. The Omar preparation plant was not utilized for processing coal in 2006. The direct-ship facility at the preparation plant can crush 500 tons per hour and the preparation plant can process 800 tons per hour. The Omar preparation plant serves CSX rail system customers with unit train shipments of up to 110 railcars. Coal is also trucked to the Homer III loadout where it is crushed and shipped to customers by rail, trucked to river docks for barge delivery, or trucked directly to customers. The Homer III loadout serves CSX rail system customers with unit train shipments of up to 100 railcars.

Delbarton. The Delbarton complex includes one underground room and pillar mine and a preparation plant. Production from the mine is transported to the Delbarton preparation plant via overland conveyor. The Delbarton preparation plant also processes coal from two surface mines of the Logan County Resource Group. The Delbarton preparation plant can process 600 tons per hour. The clean coal product is shipped to customers via the Norfolk Southern railway in unit trains of up to 110 railcars.

Edwight. The Edwight complex includes one underground room and pillar mine, a surface mine, a highwall miner and the Goals preparation plant. Production from all of the mines is transported via conveyor system to the Goals preparation plant. The Goals preparation plant can process 800 tons per hour. The rail loading facility serves CSX railway customers with unit trains of up to 100 railcars.

Elk Run. The Elk Run complex produces coal from three underground room and pillar mines and the Logans Fork longwall. Two of the room and pillar mines belt coal and one mine trucks coal to the Elk Run preparation plant, while the longwall belts coal to the preparation plant of the Marfork Resource Group. Additionally, Elk Run processes coal produced by surface mines of the Progress Resource Group and transported via underground conveyor system. The Elk Run preparation plant has a processing capacity of 2,200 tons per hour. Elk Run also operates a 200 ton per hour stoker facility that produces screened, small dimension coal for certain of our industrial customers. Customer shipments are loaded on the CSX rail system in unit trains of up to 150 railcars.

Endurance. The Endurance complex includes a surface mine, highwall miner and a direct-ship loadout. A portion of the production from the surface mine is loaded for shipment to customers at the direct ship loadout and the remainder is trucked to a conveyor system, which transports the coal to the preparation plant at the Independence Resource Group for processing.

Green Valley. The Green Valley complex includes two underground room and pillar mines and a preparation plant. The Green Valley preparation plant, which has a processing capacity of 600 tons per hour, receives coal from the mines via trucks. The rail loading facility services customers on the CSX rail system with unit train shipments of up to 75 railcars.

Independence. The Independence complex includes the Revolution longwall mine, one underground room and pillar mine and a preparation plant. Production from the underground mine is transported via underground conveyor system to a stockpile, where it is transferred to trucks for processing at the Independence preparation plant. The Black Castle surface mine and highwall miner and the surface mine at the Endurance Resource Group transport coal requiring processing to the Independence preparation plant via conveyor system. The Independence plant has a processing capacity of 2,200 tons per hour. Customers are served via rail shipments on the CSX rail system in unit trains of up to 150 railcars.

Kepler. The Kepler complex includes one underground room and pillar mine. The mine trucks coal to a third-party preparation plant for washing and shipment to customers via the Norfolk Southern railway system.

Logan County. The Logan County complex includes three surface mines, two highwall miners, one underground room and pillar mine and the Aracoma longwall mine, plus the Bandmill preparation plant and the Feats loadout, all on the CSX rail system. The surface mines and the highwall miners deliver coal to the Bandmill plant via truck and conveyor system, while both underground mines belt coal directly to this plant. The Feats loadout, which is currently idle, can service customers via the CSX rail system with unit train shipments of up to 80 cars. The Bandmill preparation plant has a processing capacity of 1,800 tons per hour. The Bandmill rail loading facility services customers via the CSX rail system with unit train shipments of up to 150 railcars.

Mammoth. The Mammoth complex operates two underground room and pillar mines and a preparation plant. Coal is transported to the preparation plant, with one mine using on-highway trucks and one mine using a conveyor system for transport to the plant. The plant has a 1,200 tons per hour processing facility capacity with barge loading capabilities on the upper Kanawha River.

Marfork. The Marfork complex includes seven underground room and pillar mines and a preparation plant. Production from five of the mines is belted directly to the preparation plant via conveyor while the remainder is trucked on private haul roads to the preparation plant. The Marfork preparation plant has a capacity of 2,400 tons per hour. Customers are served via the CSX rail system with unit trains of up to 150 railcars.

Nicholas Energy. The Nicholas Energy complex includes an underground room and pillar mine, a large surface mine, a highwall miner and a preparation plant. Coal from the underground mine is transported to the preparation plant for processing via conveyor system. Coal from the highwall miner and the portion of surface mined coal requiring processing is transported to the preparation plant using off-road trucks. Coal not requiring processing is transported via off road trucks to a conveyor system that moves the coal directly to a rail loadout facility. The plant has a processing capacity of 1,200 tons per hour. Coal shipments are loaded into rail cars for delivery via the Norfolk Southern railway in unit trains of up to 140 railcars, or are transported via on-highway trucks to the Mammoth Resource Group's barge loading facility.

Progress. The Progress complex includes the large Twilight MTR surface mine. A dragline is also utilized at the Twilight MTR surface mine. Production from the Twilight MTR surface mine is transported via underground conveyor to the Elk Run Resource Group for processing and rail shipment.

Rawl. The Rawl complex includes three underground room and pillar mines and a preparation plant. Production from one of the mines is transported to the preparation plant of the Sidney Resource Group via truck, while the other two mines transport coal via truck to the preparation plant of the Stirrat Resource Group. The Rawl plant, which was idled in December 2006, has a throughput capacity of 1,450 tons per hour. Customers are served via the Norfolk Southern railway with unit trains of up to 150 railcars.

Republic Energy. The Republic Energy complex consists of one surface mine. Direct-ship coal is trucked using on-highway trucks to various docks on the Kanawha River for barge delivery to customers.

Stirrat. The Stirrat complex includes one surface mine, a preparation plant and the Superior loadout. The surface mine belts coal directly to two 12,500 ton silos at the Superior loadout. The Superior loadout serves CSX railway customers with unit trains of up to 100 railcars. The Stirrat preparation plant cleans coal from two adjacent underground room and pillar mines of the Rawl Resource Group. The plant has a rated capacity of 600 tons per hour. Customers are served via the CSX rail system with unit trains of up to 100 railcars.

Kentucky Resource Groups

Coalgood Energy. The Coalgood Energy complex includes one surface mine and a direct-ship loadout. The coal is trucked off-road to the loadout, which serves CSX railway customers with unit trains of up to 75 railcars. The Coalgood Energy complex was idled in January 2007.

Long Fork. The Long Fork preparation plant processes coal produced by two underground room and pillar mines of the Sidney Resource Group. All production is transported via conveyor system to the Long Fork preparation plant for processing and shipping to customers. The Long Fork plant has a rated capacity of 1,500 tons per hour. The rail loading facility services customers on the Norfolk Southern railway with unit trains of up to 150 railcars.

Martin County. The Martin County complex includes one underground mine, a surface mine and a preparation plant. The direct-ship coal production from the surface mine is shipped to river docks via truck. The balance of the coal production is transported by conveyor belt or truck to the preparation plant for processing. Martin County's preparation plant has a throughput capacity of 1,500 tons per hour, although the throughput capacity is limited due to decreased impoundment availability. The coal from the preparation plant is shipped either via the Norfolk Southern railway in unit trains of up to 125 railcars or to river docks via truck. The Martin County complex, including the two mines and preparation plant, was idled in January 2007.

New Ridge. The New Ridge complex loads clean coal that is transported via truck from the preparation plant of the Sidney Resource Group and coal trucked directly from Sidney's surface mine. The New Ridge preparation plant has a capacity of 800 tons per hour. The preparation plant is currently idle but may be reactivated from time to time during 2007 as needed. All coal is loaded for shipment to customers via the CSX rail system in unit trains of up to 100 railcars.

Sidney. The Sidney complex includes six underground room and pillar mines, one surface mine, a highwall miner, a preparation plant and a direct-ship loadout facility. The direct-ship loadout facility, which is currently idle, is capable of servicing customers on the Norfolk Southern system with unit trains of up to 110 railcars. Two of the underground mines transport coal via underground conveyor system to the Long Fork Resource Group for processing and shipment, and the remainder of the underground mines transport production via underground conveyor system or truck to Sidney's preparation plant. A portion of the coal from Sidney's preparation plant and coal from the surface mines are trucked to the New Ridge Resource Group for loading into railroad cars. Sidney's preparation plant has a capacity of 1,500 tons per hour. The rail loading facility at the preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 140 railcars.

Virginia Resource Group

Knox Creek. The Knox Creek complex includes one underground room and pillar mine and a preparation plant. Production from the mine is belted by conveyor system to the preparation plant. The preparation plant has a feed capacity of 650 tons per hour. The preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 100 railcars.

Active Mines

The following chart lists the active mines, by type, at the Resource Groups as of January 31, 2007.

Resource Group	Surface Mine		Underground Mine		Total
Black Castle	1	(1 HW) [(1)]	-		1
Delbarton	-		1		1
Edwight	1	(1 HW)	1		2
Elk Run	-		4	(1 LW) [(2)]	4
Endurance	1	(1 HW)	-		1
Green Valley	-		2		2
Independence	-		2	(1 LW)	2
Kepler	-		1		1
Knox Creek	-		1		1
Logan County	3	(2 HW)	2	(1 LW)	5
Mammoth	-		2		2
Marfork	-		7		7
Nicholas Energy	1	(1 HW)	1		2
Progress	1		-		1
Rawl	-		3		3
Republic Energy	1		-		1
Sidney	1	(1 HW)	6		7
Stirrat	1		-		1
Total	11	(7 HW)	33	(3 LW)	44

(1) HW—highwall miners operated in conjunction with surface mines
(2) LW—longwall mine

Other Related Operations

We have other related operations and activities in addition to our normal coal production and sales business. The following business activities are included in this category:

Synfuel Plant. One of our subsidiaries, Marfork Coal Company, manages a synthetic fuel manufacturing facility located adjacent to the Marfork complex in Boone County, West Virginia. This facility converts coal products to synthetic fuel. Appalachian Synfuel, LLC ("Appalachian Synfuel"), the entity that owns the facility, became a wholly owned subsidiary of ours in connection with the Spin-Off. Appalachian Synfuel obtained a private letter ruling from the Internal Revenue Service ("IRS") providing that production from this synfuel facility qualifies the owner for tax credits pursuant to Section 45K (formerly Section 29) of the Internal Revenue Code of 1986, as amended ("IRC"). These tax credits are scheduled to expire December 31, 2007.

The ownership interest in Appalachian Synfuel is divided into three tranches, Series A, Series B and Series C. In 2001 and 2002, we sold a total of 99% of our Series A and Series B interests, respectively, contingent upon favorable IRS rulings that were obtained. We received cash of $7.2 million, a recourse promissory note for $34.6 million that is being paid in quarterly installments of $1.9 million including interest, and a contingent promissory note that is paid on a cents per Section 45K credit dollar earned based on synfuel tonnage shipped. A deferred gain of $4.8 million as of December 31, 2006 is included in Other noncurrent liabilities to be recognized in 2007.

The payments to be received under the contingent promissory note are reduced or eliminated if the price of oil remains above a certain threshold price set by the IRS (the "threshold price"). Once the threshold price is reached, the Section 45K credits are phased out ratably over a $13.50 per barrel range above the threshold price. The threshold price for 2006 is expected to be set by the IRS in April 2007. For fiscal year 2006, the average price of West Texas Intermediate crude oil was approximately $66.09 per barrel. At this price level a portion of the Section 45K credits for 2006 will likely be phased out, which reduced the amount of income we accrued in 2006 from payments to be received under the contingent promissory note. See Note 14 to the Notes to Consolidated Financial Statements for further information regarding Appalachian Synfuel.

Coal Handling Facilities. In 2004, we sold an interest in a joint venture that owns and operates third-party end-user coal handling facilities. Certain subsidiaries currently operate the coal handling facilities for the joint venture. As of December 31, 2006 and 2005, there was $9.7 million and $10.7 million, respectively, of deferred gain recorded in Other noncurrent liabilities, to be recognized in future periods.

Gas Operations. We hold interests in operations that produce, gather and market natural gas from shallow reservoirs in the Appalachian Basin. In the eastern U.S., conventional natural gas reservoirs are located in various types of sedimentary formations at depths ranging from 2,000 to 15,000 feet. The depths of the reservoirs drilled and operated by us range from 2,500 to 5,600 feet.

Nearly all of our gas production is from operations in southern West Virginia. In this region, we own and operate approximately 168 wells, 190 miles of gathering line, and various small compression facilities. Our southern West Virginia operations control approximately 27,000 acres of drilling rights. In addition, we own a majority working interest in 46 wells operated by others, and minority working interests in approximately 30 wells operated by others. The December 2006 average daily production, from the 214 wells owned or controlled, was 1.7 million cubic feet per day. We do not consider our current gas production level, revenues or costs to be material to our cash flows, results of operations or financial condition.

Other. From time to time, we also engage in the sale of certain non-strategic assets such as timber, oil and gas rights, surface properties and reserves. In addition, we have established several contractual arrangements with customers where services other than coal supply are provided on an ongoing basis. None of these contractual arrangements is considered to be material. Examples of such other services include arrangements with several metallurgical and industrial customers to coordinate shipment of coal to their stockpiles, maintain ownership of the coal inventory on their property and sell tonnage to them as it is consumed. We work closely with customers to provide other services in response to the current needs of each individual customer.

Marketing and Sales

Our marketing and sales force, based in the corporate office in Richmond, Virginia, includes sales managers, distribution/traffic managers and administrative personnel.

During the year ended December 31, 2006, we sold 39.1 million tons of produced coal for total Produced coal revenue of $1.9 billion. The breakdown of produced tons sold by market served was 71% utility, 20% metallurgical and 9% industrial. Sales were concluded with over 100 customers. Export shipment revenue totaled approximately $278.2 million, representing approximately 15% of 2006 Produced coal revenue. Our 2006 export shipments serviced customers in 12 countries across the globe, which included Brazil, Canada, Egypt, Finland, Germany, India, Japan, Italy, Netherlands, South Korea, Spain and Sweden. Sales are made in U.S. dollars, which minimizes foreign currency risk.

Distribution

We employ transportation specialists who negotiate freight and terminal agreements with various providers, including railroads, barge lines, ocean-going vessels, bulk motor carriers and terminal facilities. Transportation specialists also coordinate with customers, mining facilities and transportation providers to establish shipping schedules that meet each customer's needs.

Our 2006 shipments of 39.1 million tons were loaded from 22 mining complexes. Rail shipments constituted 91% of total shipments, with 27% loaded on Norfolk Southern trains and 64% loaded on CSX trains. The balance was shipped from mining complexes via truck or barge.

Approximately 27% of production was ultimately delivered via the inland waterway system. Coal is loaded directly into barges, or is transported by rail or truck to docks on the Ohio, Big Sandy and Kanawha Rivers and then ultimately transported by barge to electric utilities, integrated steel producers and industrial consumers served by the inland waterway system. We also moved approximately 6% of our production to Great Lakes' ports for transport to various U.S. and Canadian customers.

Customers and Coal Contracts

We have coal supply commitments with a wide range of electric utilities, steel manufacturers, industrial customers and energy traders and brokers. By offering coal of both steam and metallurgical grades, we are able to serve a diverse customer base. This market diversity allows us to adjust to changing market conditions and sustain high sales volumes. The majority of our customers purchase coal for terms of one year or longer, but we also supply coal on a spot basis for some customers. Our biggest customer, affiliates of American Electric Power Company, Inc., accounted for 11.1% of total fiscal year 2006 Produced coal revenue.

As is customary in the coal industry, we enter into long-term contracts (one year or more in duration) with many of our customers. These arrangements allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. The terms of long-term contracts are a result of extensive negotiations with customers. As a result, the terms of these contracts vary with respect to price adjustment mechanisms, pricing terms, permitted sources of supply, force majeure provisions, quality adjustments and other parameters. Some of the contracts contain price adjustment mechanisms that allow for changes to prices based on statistics from the U.S. Department of Labor. Coal quality specifications may be especially stringent for steel customers.

For the year ended December 31, 2006, approximately 94% of coal sales volume was pursuant to long-term contracts. We believe that in 2007, coal sales volume percentage pursuant to long-term arrangements will be comparable to 2006. As of January 31, 2007, we had contractual sales commitments of approximately 106 million tons, including commitments subject to price reopener and/or optional tonnage provisions. Remaining contractual terms of our sales commitments range from one to 14 years with an average volume-weighted remaining term of approximately 2.6 years. Eighty-four percent of the contracted sales tons are priced. As of January 31, 2007, we have committed most of our expected 2007 production. In addition, we purchase coal from third-party coal producers from time to time to supplement production and resell this coal to customers.

Competition

The coal industry in the U.S. and overseas is highly competitive. We compete with both domestic and foreign producers for sales to both domestic and foreign markets. The NMA estimated that in 2005 there were 24 coal companies in the U.S. with annual production in excess of 5 million tons, which together account for approximately 82% of U.S. production. According to the EIA, we were the sixth largest coal company in terms of tons produced in 2005, exceeded by Peabody Energy Corporation ("Peabody"), Rio Tinto Energy America, Inc., Arch Coal, Inc. ("Arch"), CONSOL Energy Inc. ("CONSOL"), and Foundation Coal Holdings Inc. ("Foundation"). However, according to EVA, we were the fourth largest U.S. coal company in terms of revenue in 2006, exceeded by Peabody, CONSOL and Arch. In addition, we compete with a wide variety of coal producers located outside of the U.S., notably companies in Australia, Canada, Columbia, Russia and Venezuela.

We are the largest producer in Central Appalachia according to EVA, with an estimated 35% of the region's production in 2005. Many small producers still compete in the region. Other significant producers in Central Appalachia include Alpha Natural Resources, Inc., CONSOL, Arch, Peabody, James River Coal Company, International Coal Group, Inc., Foundation, Rhino Resources (CAM Mining, LLC) and Alliance Resource Partners, L.P.

We compete with other producers primarily on the basis of price, coal quality, transportation cost and reliability of supply. Continued demand for coal is also dependent on factors outside of our control, including demand for electricity and steel, due to general economic conditions, environmental and governmental regulations, weather, technological developments, and the availability and cost of alternative fuel sources.

From 2003 to early 2006, a significant demand/supply imbalance of coal developed, resulting in record high prices for coal producers in the U.S. Increased worldwide demand was primarily driven by significantly higher prices for oil and natural gas and economic expansion, particularly in China and elsewhere in Asia. At the same time, infrastructure and regulatory limitations in China contributed to a tightening of worldwide coal supply, affecting global prices of coal. China's growth caused an increase in worldwide demand for raw materials and a disruption of expected coal exports to Japan, Korea, India and other countries. During 2006, the market prices of steam coal gradually dropped as a warm winter and mild summer weather in the U.S. allowed utilities to rebuild their stockpiles. Demand and prices for oil and natural gas also dropped during this period, as natural gas injections reached an all-time high in the fall of 2006.

The increased demand and prices for coal from 2003 to 2005 also encouraged coal producers in the U.S., Canada, Australia and elsewhere to expand supplies of coal, resulting in increased competition and contributing to the higher utility inventories and lower prices in 2006. Capacity expansion has been somewhat limited, however, by the increased costs of mining, high capital requirements, coal seam degradation, labor shortages, transportation issues related to rail, barge and truck shipments, higher costs related to compliance with new regulations, the difficulty of obtaining permits and bonding, and other factors.

We sell coal under long-term contracts and on the spot market. See the "Customers and Coal Contracts" section above. Generally, the relative competitiveness of coal vis-à-vis other fuels or other coals is evaluated on a delivered cost per heating value unit (Btu) basis. In addition to the price of alternative sources of fuels, coal quality, the marginal cost of producing coal in various regions of the country and transportation costs are major determinants of the price for which our production can be sold.

Factors that directly influence production cost include geological characteristics (including seam thickness), overburden ratios, depth of underground reserves, transportation costs and labor availability and cost. Central Appalachian coal is more expensive to mine than western U.S. coal because there is a high percentage of underground coal in the east and eastern surface coal tends to have thinner coal seams. Additionally, underground mining has higher costs for labor (including reserves for future costs associated with labor benefits and health care) and capital (including modern mining equipment and construction of extensive ventilation systems) than those of surface mining. The lower production costs in the western mines are offset somewhat by the higher quality of many eastern coals and higher transportation costs from western mines to many coal-fired power plants in the U.S. Demand for our coal and the prices that we will be able to obtain for it are also affected by the price and availability of high sulfur coal, which can be marketed in tandem with emissions allowances. In addition, more widespread installation by electric utilities of technology that reduces sulfur emissions is making high sulfur coal more competitive with low sulfur coal. The intraregional and interregional landscape of U.S. coal companies is highly competitive as producers seek to position themselves as the low-cost producer and supplier of choice to the electricity generating industry.

Transportation costs are another fundamental factor affecting coal industry competition. Coordination of coal transportation from many eastern loadouts, large numbers of small shipments, difficult terrain and labor issues all combine to make shipments originating in the eastern U.S. inherently more expensive on a per-mile basis than shipments originating in the western U.S. However, the total cost and availability of coal transportation from the western coal producing areas into Central Appalachian markets has historically limited the use of western coal in those markets. Barge transportation is the lowest cost method of transporting coal long distances in the eastern U.S., and the large numbers of eastern producers with river access help keep coal prices competitive.

The cost of ocean transportation and the valuation of the U.S. dollar in relation to foreign currencies significantly impact the relative attractiveness of our coal as we compete on price with other foreign coal producing sources. During the past 12 months, ocean freight rates have increased by approximately 68% as the availability of vessels has declined and fuel costs have increased. During the same period, the U.S. dollar weakened against the Eurodollar and most other global currencies, thus making the purchase of American products less expensive.

The primary competitor to eastern U.S.-based coal exporters is Australia. Over the last 3 years, Australia has expanded its production capacity to serve its natural European and Asian markets as China reduced export levels in the Pacific Rim. Its rail and port transportation infrastructure have struggled to support that expanded capacity and significant vessel loading delays continue to restrict Australia's ability to exploit the increased demand. Exports to western Europe from Massey's primary export loading facility in Newport News, Virginia continue to enjoy a significant ocean freight cost advantage, allowing our exported coal to remain competitive.

These factors, as well as rail rates and availability of import port capacity in the U.S., also impact the competitiveness of imported coal to U.S. utilities. During the last two years, a number of southeastern U.S. ports have announced plans for increasing their import capacity. As this capacity becomes available, we will likely see increased volumes of imported coal, however the extent of the impact will be limited by geography and the cost and availability of inbound rail transportation.

Employees and Labor Relations

As of December 31, 2006, we had 5,517 employees, including 134 employees affiliated with the United Mine Workers of America ("UMWA"). Relations with employees are generally good, and there have been no material work stoppages in the past ten years.

Executive Officers of the Company

Our current executive officers are:

Don L. Blankenship, Age 57

Mr. Blankenship has been a director since 1996. He has been Chairman, Chief Executive Officer and President since November 30, 2000. He has been Chairman, Chief Executive Officer and President of A.T. Massey Coal Company, Inc., our wholly owned and sole, direct operating subsidiary, since 1992.Mr. Blankenship was formerly President and Chief Operating Officer from 1990 to 1991 and President of our subsidiary, Massey Coal Services, Inc., from 1989 to 1991. He joined our subsidiary, Rawl Sales & Processing Co., in 1982. He is a director of the Center for Energy and Economic Development, the National Mining Association and the U.S. Chamber of Commerce.

Baxter F. Phillips, Jr., Age 60

Mr. Phillips has been Executive Vice President and Chief Administrative Officer since November 2004. Mr. Phillips previously served as Senior Vice President and Chief Financial Officer from September 2003 to November 2004 and as Vice President and Treasurer from 2000 to August 2003. Mr. Phillips joined us in 1981 and has also served in the roles of Corporate Treasurer, Manager of Export Sales and Corporate Human Resources Manager, among others.

J. Christopher Adkins, Age 43

Mr. Adkins has been Senior Vice President and Chief Operating Officer since July 2003. Mr. Adkins joined our subsidiary, Rawl Sales & Processing Co., in 1985 to work in underground mining. Since that time, he has served as section foreman, plant supervisor, President of our Eagle Energy subsidiary, Director of Production of Massey Coal Services, Inc. and, most recently, Vice President of Underground Production.

H. Drexel Short, Jr., Age 50

Mr. Short has been Senior Vice President, Group Operations since 1995. Mr. Short was formerly Chairman of the Board and Chief Coordinating Officer of Massey Coal Services from 1991 to 1995. Mr. Short joined us in 1981 and has served in a variety of capacities.

Michael K. Snelling, Age 50

Mr. Snelling has been Vice President, Surface Operations of Massey Coal Services, Inc. since June 2005. Mr. Snelling was formerly Director of Surface Mining of Massey Coal Services, Inc. from July 2003 until May 2005. Mr. Snelling joined us in 2000 and has served us in a variety of capacities, including President of Nicholas Energy Co. Prior to joining us, Mr. Snelling held various positions in the coal industry including engineer, production supervisor, plant supervisor, general foreman, manager of contract mining, superintendent, mine manager and vice president of operations.

Michael D. Bauersachs, Age 42

Mr. Bauersachs has been Vice President, Planning since May 2005. Mr. Bauersachs joined us in 1998, and served as Director of Acquisitions from 1998 until 2005. Prior to joining us, Mr. Bauersachs held various positions with Zeigler Coal Holding Company and Arch Mineral Corporation.

Thomas J. Dostart, Age 51

Mr. Dostart has been Vice President, General Counsel & Assistant Secretary since May 2003. He served from 1997 to April 2003 as General Counsel & Assistant Secretary for Alliance Coal, LLC. Mr. Dostart previously served as Vice President, General Counsel & Secretary for National Auto Credit, Inc., and as a corporate and securities attorney with oil and gas companies Amoco Corporation and Diamond Shamrock, Inc., and the law firms of Jones Day and Arter & Hadden.

Richard R. Grinnan, Age 38

Mr. Grinnan has been Vice President and Corporate Secretary since March 2006. He served as Senior Corporate Counsel from July 2004 until May 2006. Prior to joining us, Mr. Grinnan was a corporate and securities attorney at the law firm of McGuireWoods LLP in Richmond, Virginia from August 2000 until July 2004.

Jeffrey M. Jarosinski, Age 47

Mr. Jarosinski has been Vice President, Finance since 1998 and Chief Compliance Officer since December 2002. From 1998 through December 2002, Mr. Jarosinski was Chief Financial Officer. Mr. Jarosinski was formerly Vice President, Taxation from 1997 to 1998 and Assistant Vice President, Taxation from 1993 to 1997. Mr. Jarosinski joined us in 1988.

John M. Poma, Age 42

Mr. Poma has been Vice President, Human Resources since April 2003. Mr. Poma served as Corporate Counsel from 1996 until 2000 and as Senior Corporate Counsel from 2000 through March 2003. Prior to joining us in 1996, Mr. Poma was an employment attorney with the law firms of Midkiff & Hiner in Richmond, Virginia and Jenkins, Fenstermaker, Krieger, Kayes & Farrell in Huntington, West Virginia.

Eric B. Tolbert, Age 39

Mr. Tolbert has been Vice President and Chief Financial Officer since November 2004. Mr. Tolbert previously served as Corporate Controller since 1999. He joined us in 1992 as a financial analyst and subsequently served as Director of Financial Reporting.

Roger T. Williams, Age 34

Mr. Williams has been Vice President, Sales since November 2006. Mr. Williams previously served as Assistant to the Office of the Chairman since July 2005. Prior to joining us, Mr. Williams worked for Deutsche Bank Group as an investment banker in the energy sector from July 2002 to June 2005, after attending Columbia Business School from January 2001 to June 2002.

David W. Owings, Age 33

Mr. Owings has been Corporate Controller and principal accounting officer since November 2004. Mr. Owings previously served as Manager of Financial Reporting since joining us in 2001. Prior to joining us, Mr. Owings worked at Ernst & Young LLP, the Company's independent registered public accounting firm, serving as a manager from January 2001 through September 2001 and as a senior auditor from October 1998 through January 2001in the Assurance and Advisory Business Services group.

Environmental, Safety and Health Laws and Regulations

We are subject to federal, state and local laws and regulations that are revised and amended from time to time relating to environmental protection and plant and mine safety and health, including, but not limited to, the Federal Surface Mining Control and Reclamation Act of 1977 ("SMCRA"); Occupational Safety and Health Act of 1970; Mine Safety and Health Act of 1977; Water Pollution Control Act of 1972 (commonly known as the Clean Water Act); Clean Air Act of 1963; Black Lung Benefits Revenue Act of 1977; and Black Lung Benefits Reform Act of 1977. We are seldom subject to permitting or enforcement under the Federal Resource Conservation and Recovery Act of 1976 or the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 and do not consider the effects of those statutes on our operations to be material for purposes of disclosure.

In 2006, we spent approximately $17.9 million to comply with environmental laws and regulations, of which $7.1 million was for reclamation, including $4.2 million for final reclamation. None of these expenditures was capitalized. We anticipate spending approximately $43.3 million and $27.9 million in such non-capital expenditures in 2007 and 2008, respectively. Of these expenditures, $32.2 million and $16.6 million for 2007 and 2008, respectively, are anticipated to be for reclamation.

We own a majority interest in Coalsolv, LLC, which holds the U.S. marketing rights for the emission control technologies on coal-fired power plants of Cansolv Technologies, Inc., in which we hold a minority interest. Cansolv's technologies remove sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury, carbon dioxide (CO_2), and other greenhouse gases from flue gas emissions. The Cansolv process has been utilized at various industrial facilities around the world, with additional projects underway in China and Canada. Through Coalsolv, we contributed funds for a pilot plant that has been utilized in the U.S. and Canada for the testing and piloting of the Cansolv SO_2, NO_X, mercury, and CO_2 capture technology on coal-fired power plants.

SMCRA

The SMCRA, which is administered by the Office of Surface Mining Reclamation and Enforcement ("OSM"), establishes mining, environmental protection and reclamation standards for all aspects of surface mining as well as many aspects of deep mining. The SMCRA and similar state statutes require, among other things, the restoration of mined property in accordance with specified standards and an approved reclamation plan. In addition, the Abandoned Mine Land Fund, which is part of the SMCRA, imposes a fee on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.35 per ton on surface-mined coal and $0.15 per ton on deep-mined coal. A mine operator must submit a bond or otherwise secure the performance of its reclamation obligations. Mine operators must receive permits and permit renewals for surface mining operations from the OSM or, where state regulatory agencies have adopted federally approved state programs under the act, the appropriate state regulatory authority. We accrue for reclamation and mine-closing liabilities in accordance with Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143") (see Note 9 to the Notes to Consolidated Financial Statements).

Clean Water Act

Section 301 of the Clean Water Act prohibits the discharge of a pollutant from a point source into navigable waters of the U.S. except in accordance with a permit issued under either Section 402 or Section 404 of the Clean Water Act. Navigable waters are broadly defined to include streams, even those that are not navigable in fact, and may include wetlands. All mining operations in Appalachia generate excess material, which must be placed in fills in adjacent valleys and hollows. Likewise, coal refuse disposal areas and coal processing slurry impoundments are located in valleys and hollows. Almost all of these areas contain intermittent or perennial streams, which are considered navigable waters under the Clean Water Act. An operator must secure a Clean Water Act permit before filling such streams. For approximately the past twenty-five years, operators have secured Section 404 fill permits that authorize the filling of navigable waters with material from various forms of coal mining. Operators have also obtained permits under Section 404 for the construction of slurry impoundments although the use of these impoundments, including discharges from them, requires permits under Section 402. Section 402 discharge permits are generally not suitable for authorizing the construction of fills in navigable waters.

Clean Air Act

Coal contains impurities, including sulfur, mercury, chlorine, nitrogen oxide and other elements or compounds, many of which are released into the air when coal is burned. The Clean Air Act and corresponding state laws extensively regulate emissions into the air of particulate matter and other substances, including sulfur dioxide, nitrogen oxide and mercury. Although these regulations apply directly to impose certain requirements for the permitting and operation of our mining facilities, by far their greatest impact on us and the coal industry generally is the effect of emission limitations on utilities and other customers. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources in an effort to comply with these air pollution standards. The U.S. Environmental Protection Agency ("EPA") has imposed or attempted to impose tighter emission restrictions in a number of areas, some of which are currently subject to litigation. The general effect of such tighter restrictions could be to reduce demand for coal. This in turn may result in decreased production and a corresponding decrease in revenue and profits.

National Ambient Air Quality Standards. In July 1997, the EPA adopted a new National Ambient Air Quality Standard ("NAAQS") for very fine particulate matter and a more stringent NAAQS for ozone. Ozone is produced by a combination of two precursor pollutants: volatile organic compounds and nitrogen oxide, a by-product of coal combustion. States have until 2007, generally, to come into compliance with these standards and will do so by revising their State Implementation Plans ("SIPs") to include provisions for the control of ozone precursors and/or particulate matter. Revised SIPs could require electric power generators to further reduce nitrogen oxide and sulfur dioxide emissions. In addition, some northeastern states may assert claims against Midwestern states or "upwind" states alleging that coal fired power plants in the upwind states are preventing the northeastern states from attaining the new NAAQS.

Acid Rain Control Provisions. The acid rain control provisions of Title IV of the Clean Air Act require a reduction of sulfur dioxide emissions from power plants. Because sulfur is a natural component of coal, required sulfur dioxide reductions can have an adverse affect on coal mining operations. All power plants of greater than 25 megawatt capacity must reduce sulfur dioxide emissions by: (i) burning lower sulfur coal, either exclusively or mixed with higher sulfur coal; (ii) installing pollution control devices such as scrubbers, which reduce the emissions from high sulfur coal; (iii) switching to fuels other than coal; (iv) reducing electricity generating levels; or (v) purchasing or trading emission credits. Specific emissions sources receive these credits that electric utilities and industrial concerns can trade or sell to allow other units to emit higher levels of sulfur dioxide. Each credit allows its holder to emit one ton of sulfur dioxide.

Regional Haze Program. Along with regulations addressing ambient air quality, the EPA has initiated a regional haze program designed to protect and to improve visibility at and around so-called Class I Areas, which are generally National Parks, National Wilderness Areas and International Parks. This program may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around the Class I Areas. Moreover, this program requires certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxide and particulate matter. EPA's final rule concerning best available retrofit technology is currently on remand to the EPA from the U.S. Court of Appeals for the D.C. Circuit. By imposing limitations upon the placement and construction of new coal-fired power plants, the EPA's regional haze program could affect the future market for coal. States have until 2007 to submit revised SIPs to address regional haze.

New Source Review Program. Under the Clean Air Act, new and modified sources of air pollution must meet certain new source standards ("New Source Review Program"). In the late 1990s, the EPA filed lawsuits against many coal-fired plants in the eastern U.S. alleging that the owners performed non-routine maintenance, causing increased emissions that should have triggered the application of these new source standards. Some of these lawsuits have been settled, with the owners agreeing to install additional pollution control devices in their coal-fired plants. The remaining litigation and the uncertainty around the New Source Review Program rules could adversely impact utilities' demand for coal in general or coal with certain specifications, including the coal produced by us.

Multi-Pollutant Strategies. In March 2005, the EPA issued two closely related rules designed to significantly reduce levels of sulfur dioxide, nitrogen oxide and mercury: the Clean Air Interstate Rule and the Clean Air Mercury Rule. The Clean Air Interstate Rule sets a cap-and-trade program in 28 states and the District of Columbia to establish emissions limits for sulfur dioxide and nitrogen oxide, by allowing utilities to buy and sell credits at a rate that will cut sulfur dioxide emissions over 70% and nitrogen oxide emissions over 60% by 2015, to assist in achieving compliance with the NAAQS for 8-hour ozone and fine particulates. The Clean Air Mercury Rule will cut mercury emissions nearly 70% by 2018 through a cap-and-trade program. Environmentalists have criticized both rules and challenged the legality of the rules in numerous lawsuits. These rules will directly affect coal producers, suppliers and utilities in the eastern and western regions of the U.S., by requiring revisions to the SIPs in many eastern states. The Clean Air Mercury Rule sets emissions limits based on coal rank, potentially giving the users of western sub-bituminous coal a significant competitive advantage over eastern bituminous coal users.

Alternative bills have been introduced in the past and were introduced in the reconstituted Congress and various states in early 2007 that would place tighter caps on coal-fired emissions, including mandatory limits on carbon dioxide emissions, and shorter implementation time frames. While the details of these proposed initiatives vary, there is a movement towards increased regulation of air emissions, including carbon dioxide and mercury, which could cause power plants to shift away from coal as a fuel source.

1992 Framework Convention on Global Climate Change

The U.S. has not implemented the 1992 Framework Convention on Global Climate Change ("Kyoto Protocol"), which became effective for many countries on February 16, 2005. The Kyoto Protocol is intended to limit or reduce emissions of greenhouse gases, such as carbon dioxide. Under the terms of the Kyoto Protocol, with specific emission targets that vary from country to country, the U.S. would be required to reduce emissions to 93% of 1990 levels over a five-year period from 2008 through 2012. Although the U.S. has not ratified the emission targets and no comprehensive regulations focusing on greenhouse gas emissions are in place, these restrictions, whether through ratification of the emission targets or other efforts to stabilize or reduce greenhouse gas emissions, could adversely affect the price and demand for coal. If the U.S. were to enact comprehensive legislation focused on the mandatory reduction of greenhouse gas emissions, it could force a large reduction in coal-fired electricity generation, as technologies for carbon dioxide sequestration are not yet widely commercially available.

Permitting and Compliance

Our operations are principally regulated under surface mining permits issued pursuant to the SMCRA and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. We currently have over 500 surface mining permits. In conjunction with the surface mining permits, most operations hold national pollutant discharge elimination system permits pursuant to the Clean Water Act and state counterpart water pollution control laws for the discharge of pollutants to waters. These permits are issued for terms of five years. Additionally, the Clean Water Act requires permits for operations that fill waters of the U.S. Valley fills and refuse impoundments are authorized under permits issued under the Clean Water Act by the U.S. Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart clean air laws allowing and controlling the discharge of air pollutants. These permits are primarily permits allowing initial construction (not operation) and they do not have expiration dates.

We believe we have obtained all permits required for current operations under the SMCRA, Clean Water Act and Clean Air Act and corresponding state laws. We believe that we are in compliance in all material respects with such permits, and routinely correct violations in a timely fashion in the normal course of operations. The expiration dates of the permits are largely immaterial as the law provides for a right of successive renewal. The cost of obtaining surface mining, clean water and air permits can vary widely depending on the scientific and technical demonstrations that must be made to obtain the permits. However, the cost of obtaining a permit is rarely more than $500,000 and the cost of obtaining a renewal is rarely more than $5,000. It is impossible to predict the full impact of future judicial, legislative or regulatory developments on our operations, because the standards to be met, as well as the technology and length of time available to meet those standards, continue to develop and change.

We believe, based upon present information available to us, that accruals with respect to future environmental costs are adequate. For further discussion on costs, see Note 9 to the Notes to Consolidated Financial Statements. However, the imposition of more stringent requirements under environmental laws or regulations, new developments or changes regarding site cleanup costs or the allocation of such costs among potentially responsible parties, or a determination that we are potentially responsible for the release of hazardous substances at sites other than those currently identified, could result in additional expenditures or the provision of additional accruals in expectation of such expenditures.

Mine Safety and Health

Safety. Stringent health and safety standards have been in effect since Congress enacted the Federal Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations.

All of the states in which we operate have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and pervasive system for protection of employee health and safety affecting any segment of U.S. industry. While regulation has a significant effect on our operating costs, our U.S. competitors are subject to the same degree of regulation.

In June 2006, Congress passed and President Bust signed the MINER Act, which, among other things, requires mine-specific emergency response plans, enhanced communication systems, and more available mine rescue teams, as well as larger penalties by MSHA for noncompliance by mine operators. In December 2006, MSHA similarly passed its final rule on Emergency Mine Evacuation, which includes requirements for increased availability and storage of SCSRs; improved emergency evacuation drills and SCSR device training; and the installation and maintenance of lifelines in underground coal mines. Coal producing states, including West Virginia and Kentucky, passed similar legislation.

Our goal is to achieve excellent safety and health performance. We measure our success in this area primarily through the use of accident frequency rates. We believe that a superior safety and health regime is inherently tied to achieving productivity and financial goals. We seek to implement this goal by: training employees in safe work practices; openly communicating with employees; establishing, following and improving safety standards; involving employees in establishing safety standards; and recording, reporting and investigating all accidents, incidents and losses to avoid reoccurrence.

Black Lung. Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to: (i) current and former coal miners totally disabled from black lung disease; and (ii) certain survivors of a miner who dies from black lung disease. The Black Lung Disability Trust Fund, to which we must make certain tax payments based on tonnage sold, provides for the payment of medical expenses to claimants whose last mine employment was before January 1, 1970 and to claimants employed after such date, where no responsible coal mine operator has been identified for claims or where the responsible coal mine operator has defaulted on the payment of such benefits. In addition to federal acts, we are also liable under various state statutes for black lung claims. Federal benefits are offset by any state benefits paid.

Workers' Compensation. We are liable for workers' compensation benefits for traumatic injuries under state workers' compensation laws in which we have operations. Workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation owed to an employee injured in the course of employment.

Coal Industry Retiree Health Benefit Act of 1992 and Tax Relief and Retiree Health Care Act of 2006. The Coal Industry Retiree Health Benefit Act of 1992 ("Coal Act") provides for the funding of health benefits for certain UMWA retirees. The Coal Act established the Combined Benefit Fund ("CBF") into which "signatory operators" and "related persons" are obligated to pay annual premiums for covered beneficiaries. The Coal Act also created a second benefit fund, the 1992 Benefit Plan, for miners who retired between July 21, 1992 and September 30, 1994 and whose former employers are no longer in business. Since 1995, the predecessor to the NMA, the NMA, the CBF and the Social Security Administration ("SSA") have litigated in multiple courts how the SSA is to calculate the per-beneficiary premium that the CBF charges assigned operators. On August 12, 2005, the U.S. District Court for the District of Maryland granted the plaintiff coal companies' motion for summary judgment, holding unlawful the SSA's June 10, 2003 decision to retroactively apply a higher premium to various coal operators, including certain of our subsidiaries. Defendants appealed the case to the United States Court of Appeals for the Fourth Circuit. On December 21, 2006, the Fourth Circuit affirmed the District Court's ruling. Subject to any further appeal, we should receive refunds or credits to future premium obligations of approximately $3 million.

Separately, on December 20, 2006, President Bush signed the Tax Relief and Retiree Health Care Act of 2006. This legislation includes important changes to the Coal Act that impacts all companies required to contribute to the CBF. Effective October 1, 2007, the SSA will revoke all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies"), but their premium relief is phased-in. The reachback companies will pay their full premium obligation in the current plan year that ends September 30, 2007. However, they will pay only 55% of their plan year 2008 assessed premiums, 40% of their plan year 2009 assessed premiums, and 15% of their plan year 2010 assessed premiums. General U.S. Treasury money will be transferred to the CBF to make up the difference. After 2010, reachback companies will have no further obligations to the CBF, and transfers from the U.S. Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies.

Available Information

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other information with the Securities and Exchange Commission ("SEC"). Our SEC filings are available to the public over the Internet at the SEC's website at www.sec.gov. You may also read and copy any document we file at the SEC's public reference room at 450 Fifth Street, NW, Washington D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. We make available, free of charge through our Internet website, www.masseyenergyco.com, our annual report, quarterly reports, current reports, proxy statements, section 16 reports and other information (and any amendments thereto) as soon as practicable after filing or furnishing the material to the SEC, in addition to, our Corporate Governance Guidelines, codes of ethics and the charters of the Audit, Compensation, Executive, Governance and Nominating, and Safety, Environmental, and Public Policy Committees. These materials also may be requested at no cost by telephone at (866) 814-6512 or by mail at: Massey Energy Company, Post Office Box 26765, Richmond, Virginia 23261, Attention: Investor Relations.

GLOSSARY OF SELECTED TERMS

Ash. Impurities consisting of iron, aluminum 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.

Bituminous coal. The most common type of coal with moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btu 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 states and regions of eastern Kentucky, eastern Tennessee, western Virginia and southern West Virginia.

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.

Continuous miner. A mining machine with a continuously rolling cutting cylinder used in underground and highwall mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.

Direct-ship coal. Coal that is shipped without first being processed.

Deep mine. An underground coal mine.

Dragline. A large machine used in the surface mining process to remove the overburden, or layers of earth and rock covering a coal seam. The dragline has a large bucket suspended from the end of a long boom. The bucket, which is suspended by cables, is able to scoop up substantial amounts of overburden as it is dragged across the excavation area.

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

Highwall Mining. Described in Item 1. Business, under the heading "Mining Methods."

High vol met coal. Coal that averages approximately 35% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

Illinois Basin. The Illinois Basin consists of the coal producing areas in Illinois, Indiana and western Kentucky.

Industrial coal. Coal used by industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Long-term contracts. Contracts with terms of one year or longer.

Longwall mining. Described in Item 1. Business, under the heading "Mining Methods."

Low vol met coal. Coal that averages approximately 20% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

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

Nitrogen oxide (NOx). Nitrogen oxide is produced as a gaseous by-product of coal combustion.

Northern Appalachia. Northern Appalachia includes all bituminous coal production in the states of Pennsylvania, Ohio and Maryland and production in the northern part of West Virginia.

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

Overburden ratio. The amount of overburden that must be removed to excavate a given quantity of coal. It is commonly expressed in cubic yards per ton of coal or as a ratio comparing the thickness of the overburden with the thickness of the coal bed.

Pillar. An area of coal left to support the overlying strata in an underground mine, sometimes left permanently to support surface structures.

Powder River Basin. The Powder River Basin consists of the coal producing areas in southeast Montana and northeast Wyoming.

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 rock and other impurities to prepare it for use by a particular customer. The washing process has the added benefit of removing some of the coal's sulfur content.

Probable reserves. Described in Item 2. Properties, under the heading "Coal Reserves."

Proven reserves. Described in Item 2. Properties, under the heading "Coal Reserves."

Reclamation. The process of restoring land and the environment to their approximate 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. Described in Item 2. Properties, under the heading "Coal Reserves."

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

Room and pillar mining. Described in Item 1. Business, under the heading "Mining Methods."

Scrubber (flue gas desulfurization unit). Any of several forms of chemical/physical devices that operate to neutralize sulfur and other greenhouse gases 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 or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as utility coal.

Stoker coal. Coal that is sized to a specific, standard range. Stoker coal is typically one quarter inch by one and one quarter to one and three quarter inch.

Sulfur. One of the elements present in varying quantities in coal that reacts with air when coal is burned to form sulfur dioxide.

Sulfur content. Coal is commonly described by its sulfur content due to the importance of sulfur in environmental regulations. "Low sulfur" coal has a variety of definitions, but typically is used to describe coal consisting of 1.0% or less sulfur. A majority of our Appalachian reserves are of low sulfur grades.

Sulfur dioxide (SO_2). Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Surface mining. Described in Item 1. Business, under the heading "Mining Methods."

Tons. A "short" or net ton is equal to 2,000 pounds. A "long" or British ton is approximately 2,240 pounds; a "metric" tonne is approximately 2,205 pounds. The short ton is the unit of measure referred to in this Annual Report on Form 10-K.

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 or conveyor to the surface.

Unit train. A railroad train of a specified number of railroad cars carrying only coal. A typical unit train can carry at least 10,000 tons of coal in a single shipment.

Utility coal. Coal used by power plants to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as steam coal.

Item 1A. Risk Factors

We are subject to a variety of risks, including, but not limited to, those risk factors set forth below and those referenced herein to other Items contained in this Annual Report on Form 10-K, including Item 1. Business, under the headings "Customers and Coal Contracts," "Competition," "Environmental, Safety and Health Laws and Regulations," Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"), under the headings "Critical Accounting Estimates and Assumptions," "Certain Trends and Uncertainties" and elsewhere in MD&A.

We are impacted by the competitiveness of the markets in which we compete and market demand for coal.

We compete with coal producers in various regions of the U.S. and overseas for domestic and international sales. Continued domestic demand for our coal and the prices that we will be able to obtain primarily will depend upon coal consumption patterns of the domestic electric utility industry and the domestic steel industry. 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, including hydroelectric power. Consumption by the domestic steel industry is primarily affected by economic growth and the demand for steel used in construction as well as appliances and automobiles. In recent years, the competitive environment for coal has been impacted by sustained growth in a number of the largest markets in the world, including the U.S., China, Japan and India, where demand for both electricity and steel have supported pricing for steam and metallurgical coal. The cost of ocean transportation and the valuation of the U.S. dollar in relation to foreign currencies significantly impact the relative attractiveness of our coal as we compete on price with other foreign coal producing sources. See Item 1. Business, under the heading "Competition," for further discussion.

Portions of our coal reserves possess quality characteristics that enable us to mine, process and market them as either metallurgical coal or high quality steam coal, depending on the prevailing conditions in the metallurgical and steam coal industries. A decline in the metallurgical market relative to the steam market could cause us to shift coal from the metallurgical market to the steam market. If demand for metallurgical coal declined to the point where we could earn a more attractive return marketing the coal as steam coal, there could be a material impact on cash flows, results of operations or financial condition.

Demand for our coal depends on its price and quality and the cost of transporting it to customers.

Coal prices are influenced by a number of factors and may vary dramatically by region. The two principal components of the price of coal are the price of coal at the mine, which is influenced by mine operating costs and coal quality, and the cost of transporting coal from the mine to the point of use. The cost of mining the coal is influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. Underground mining is generally more expensive than surface mining as a result of higher costs for labor (including reserves for future costs associated with labor benefits and health care) and capital costs (including costs for mining equipment and construction of extensive ventilation systems). As of January 31, 2007, we operated 33 active underground mines, including 3 longwall mines, and 11 active surface mines, with 7 highwall miners. See Item 1. Business, under the headings "Mining Methods," "Mining Operations" and "Competition" for further discussion. Increases in transportation costs could make coal a less competitive source of energy. Such increases could have a material impact on our ability to compete with other energy sources and on our cash flows, results of operations or financial condition. On the other hand, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country. See Item 1. Business, under the heading "Competition," for further discussion.

A significant decline in coal prices in general could adversely affect our operating results and cash flows.

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.

We depend on continued demand from our customers.

Reduced demand from or the loss of our largest customers could have an adverse impact on our ability to achieve projected revenue. Decreases in demand may result from, among other things, a reduction in consumption by the electric generation industry and/or the steel industry, the availability of other sources of fuel at cheaper costs and a general slow-down in the economy. When our contracts with customers reach expiration, there can be no assurance that the customers either will extend or enter into new long-term contracts or, in the absence of long-term contracts, that they will continue to purchase the same amount of coal as they have in the past or on terms, including pricing terms, as favorable as under existing arrangements. In the event that a large customer account is lost or a long-term contract is not renewed, profits could suffer if alternative buyers are not willing to purchase our coal on comparable terms. See Item 1. Business, under the heading "Customers and Coal Contracts" for further discussion.

The level of our indebtedness could adversely affect our ability to grow and compete and prevent us from fulfilling our obligations under our contracts and agreements.

At December 31, 2006, we had $1,104.9 million of total indebtedness outstanding, which represented 61.3% of our total book capitalization. We have significant debt, lease and royalty obligations. Our ability to satisfy debt service, lease and royalty obligations and to effect any refinancing of indebtedness will depend upon future operating performance, which will be affected by prevailing economic conditions in the markets that we serve as well as financial, business and other factors, many of which are beyond our control. We may be unable to generate sufficient cash flow from operations and future borrowings, or other financings may be unavailable in an amount sufficient to enable us to fund our debt service, lease and royalty payment obligations or our other liquidity needs.

Our relative amount of debt could have material consequences to our business, including, but not limited to: (i) making it more difficult to satisfy debt covenants and debt service, lease payments and other obligations; (ii) making it more difficult to pay quarterly dividends as we have in the past; (iii) increasing our vulnerability to general adverse economic and industry conditions; (iv) limiting our ability to obtain additional financing to fund future acquisitions, working capital, capital expenditures or other general corporate requirements; (v) reducing the availability of cash flows from operations to fund acquisitions, working capital, capital expenditures or other general corporate purposes; (vi) limiting our flexibility in planning for, or reacting to, changes in the business and the industry in which we compete; or (vii) placing us at a competitive disadvantage with competitors with relatively lower amounts of debt.

The covenants in our credit facility and the indentures governing debt instruments impose restrictions that may limit our operating and financial flexibility.

Our asset based loan credit facility and the indentures governing our notes contain a number of significant restrictions and covenants that may limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create lien or security interests in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries.

Operating results below current levels or other adverse factors, including a significant increase in interest rates, could result in us being unable to comply with certain debt covenants. 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 the lenders. If the 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 or on terms that are acceptable to us. If our debt is in default for any reason, our cash flows, results of operations or financial condition could be materially and adversely affected. In addition, complying with these covenants may also cause us to take actions that are not favorable to holders of the notes and may make it more difficult for us to successfully execute our business strategy and compete against companies that are not subject to such restrictions.

We depend on our ability to continue acquiring and developing economically recoverable coal reserves.

A key component our future success is our ability to continue acquiring coal reserves for development that have the geological characteristics that allow them to be economically mined. Replacement reserves may not be available or, if available, may not be capable of being mined at costs comparable to those characteristics of the depleting mines. An inability to continue acquiring economically recoverable coal reserves could have a material impact on cash flows, results of operations or financial condition.

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

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by us. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (i) geological conditions; (ii) historical production from the area compared with production from other producing areas; (iii) the effects of regulations and taxes by governmental agencies; (iv) future prices; and (v) future operating costs.

Each of these factors may 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 may vary substantially. As a result, our estimates may not accurately reflect our actual reserves. Actual production, revenues and expenditures with respect to reserves will likely vary from estimates, and these variances may be material.

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.

A significant portion of our mining operations occurs on properties that we lease. Title defects or the loss of leases could adversely affect our ability to mine the reserves covered by those leases. Our current practice is to obtain a title review from a licensed attorney prior to leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. Separate title confirmation sometimes is not required when leasing reserves where mining has occurred previously. Our right to mine some of our reserves may be adversely affected if defects in title or boundaries exist. In order to obtain leases to conduct our mining operations on property where these defects exist, we may have to incur unanticipated costs. In addition, we may not be able to successfully 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.

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

The recent strong coal market and increased demand for coal has attracted new investors to the coal industry, spurring the development of new mines, and resulting in added production capacity throughout the industry. Several of our competitors have announced plans for substantial increases in productive capacity over the next several years, although recent weakness in coal pricing has led to the deferral of some of these projects. A rebound in the price levels of coal could further encourage the development of expanded capacity by new or existing coal producers. Any resulting increases in capacity could further reduce coal prices and reduce our margins. See Item 1. Business, under the heading "Competition," for further discussion.

Decreased availability or increased costs of key equipment, supplies or commodities such as diesel fuel, steel, explosives and tires could decrease our profitability.

Our operations are dependant on reliable supplies of mining equipment, replacement parts, explosives, diesel fuel, tires, and steel-related products (including roof bolts). If the cost of any mining equipment or key supplies increases significantly, or if they should become unavailable due to higher industry-wide demand or less production by suppliers, there could be an adverse impact on our cash flows, results of operations or financial condition. In the past two years, industry-wide demand growth has exceeded supply growth for certain surface and underground mining equipment and heavy equipment tires.

Transportation disruptions could impair our ability to sell coal.

We are dependent on our transportation providers to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lockouts or other events could temporarily impair our ability to supply coal to customers.

In recent years, our ability to ship coal has been negatively impacted by a reduction in available and timely rail service. Lack of sufficient resources to meet the rapid increase in demand, a greater demand for transportation to export terminals and rail line congestion all seem to have contributed to the disruption and slowdowns in rail service. Although the railroads continue to take action to remedy these issues, including the purchase of new locomotives and railcars, and the hiring and training of additional crews, such actions may not be sufficient to cure the disruption and slowdowns in rail service.

Severe weather may affect our ability to mine and deliver coal.

Severe weather, including flooding and excessive ice or snowfall, when it occurs, can adversely affect our ability to produce, load and transport coal, which may negatively impact cash flows, results of operations or financial condition.

Federal and state government regulations applicable to operations increase costs and may make our coal less competitive than other coal producers.

We incur substantial costs and liabilities under increasingly strict federal, state and local environmental, health and safety and endangered species laws, regulations and enforcement policies. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. See Item 1. Business, under the heading "Environmental, Safety and Health Laws and Regulations" for further discussion of this risk.

New legislation and new regulations may be adopted which could materially adversely affect our mining operations, cost structure or our customers' ability to use coal. New legislation and new regulations may also require us, as well as our customers, to change operations significantly or incur increased costs. The EPA has undertaken broad initiatives aimed at increasing compliance with emissions standards and to provide incentives to our customers for decreasing emissions, often by switching to an alternative fuel source or by installing scrubbers at their coal-fired plants.

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

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

We must obtain governmental permits and approvals for mining operations, which can be a costly and time-consuming process and can result in restrictions on our operations.

Our operations are principally regulated under surface mining permits issued pursuant to the SMCRA and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. Additionally, the Clean Water Act requires permits for operations that fill waters of the U.S. Valley fills and refuse impoundments are typically authorized under nationwide permits that are revised and renewed periodically by the U.S. Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart clean air laws allowing and controlling the discharge of air pollutants. Regulatory authorities exercise considerable discretion in the timing of permit issuance. Requirements imposed by these authorities may be costly and time-consuming and may result in delays in the commencement or continuation of exploration or production operations. See Item 1. Business, under the heading "Environmental, Safety and Health Laws and Regulations" for further discussion.

The loss of key personnel or the failure to attract qualified personnel could affect our ability to operate our company effectively.

The successful management of our business is dependent on a number of key personnel. Our future success will be affected by our continued ability to attract and retain highly skilled and qualified personnel. There are no assurances that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have an adverse affect on our cash flows, results of operations or financial condition.

Union represented labor creates an increased risk of work stoppages and higher labor costs.

At December 31, 2006, 2.4% of our total workforce was represented by the UMWA. Six of our coal preparation plants and one smaller surface mine have a workforce that is represented by the UMWA. In 2006, these six preparation plants handled approximately 29% of our coal production. There may be an increased risk of strikes and other related work actions, in addition to higher labor costs, associated with these operations. If some or all of our current open shop operations were to become union represented, we could be subject to additional risk of work stoppages and higher labor costs, which could adversely affect the stability of production and reduce net income.

We are subject to being adversely affected by a decline in the financial condition and creditworthiness of our customers.

In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or events may trigger the application of tighter terms of sale, requirements for collateral or, ultimately, a suspension of credit privileges. The creditworthiness of customers can limit who we can do business with and at what price.

We have contracts to supply coal to energy trading and brokering companies who resell the coal to the ultimate users. We are subject to being adversely affected by any decline in the financial condition and creditworthiness of these energy trading and brokering companies. In addition, as the largest supplier of metallurgical coal to the American steel industry, we are subject to being adversely affected by any decline in the financial condition or production volume of American steel producers. See Item 1. Business, under the heading "Customers and Coal Contracts" for further discussion.

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

We are parties to a number of legal proceedings incident to normal business activities. Some of the allegations brought against us are with merit, while others are not. There is always the potential that an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Item 3. Legal Proceedings and Note 17 to the Notes to Consolidated Financial Statements for further discussion.

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

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by management and engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly. See Item 1. Business, under the heading "Environmental, Safety and Health Laws and Regulations" for further discussion.

Our future expenditures for postretirement benefit and pension obligations could be materially higher than we have predicted if our underlying assumptions are incorrect.

We are subject to long-term liabilities under a variety of benefit plans and other arrangements with current and former employees. These obligations have been estimated based on actuarial assumptions, including actuarial estimates, assumed discount rates, estimates of life expectancy, expected returns on pension plan assets and changes in healthcare costs.

If our assumptions relating to these benefits change in the future or are incorrect, we may be required to record additional expenses, which would reduce our profitability. 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 impact on our cash flows, results of operations or financial condition. For a further discussion, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading "Critical Accounting Estimates and Assumptions" and Notes 5 and 10 to the Notes to Consolidated Financial Statements.

We may not realize all or any of the anticipated benefits from acquisitions we undertake, as acquisitions entail a number of inherent risks.

From time to time we expand our business and reserve position 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 ability 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 these acquisitions.

Foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We rely on customers in other countries for a portion of our sales, with shipments to countries in North America, South America, Europe, Asia and Africa. We compete in these international markets against coal produced in other countries. Coal is sold internationally in U.S. dollars. As a result, mining costs in competing producing countries may be reduced in U.S. dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

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

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 U.S. or its allies, or military or trade disruptions affecting customers may materially adversely affect operations. As a result, there could be delays or losses in transportation and deliveries of coal to customers, decreased sales of coal and extension of time for payment of accounts receivable from customers. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the U.S. In addition, such disruption may lead to significant increases in energy prices that could result in government-imposed price controls. It is possible that any, or a combination, of these occurrences could have a material impact on cash flows, results of operations or financial condition.

Coal mining is subject to inherent risks, some of which we insure against and some of which we self-insure.

Our operations are subject to certain events and conditions that could disrupt operations, including fires and explosions, accidental minewater discharges, natural disasters, equipment failures, maintenance problems and flooding. We maintain insurance policies that provide limited coverage for some, but not all, of these risks. Even where insurance coverage applies, there can be no assurance that these risks would be fully covered by insurance policies. We self-insure our highwall miners and underground equipment, including our longwalls. We do not currently carry business interruption insurance.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We have owned and leased properties totaling more than 976,000 acres in West Virginia, Kentucky, Virginia, Pennsylvania and Tennessee. In addition, certain of our owned or leased properties are leased or subleased to third party tenants. Our current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. Separate title confirmation sometimes is not required when leasing reserves where mining has occurred previously. We currently own or lease the equipment that is utilized in mining operations. The following table describes the location and general character of the major existing facilities, exclusive of mines, coal preparation plants and their adjoining offices.

Administrative Offices:

Richmond, Virginia	Owned	Massey Corporate Headquarters
Charleston, West Virginia	Leased	Massey Coal Services Headquarters
Chapmanville, West Virginia	Leased	Massey Coal Services Field Office

For a description of mining properties, see Item 1. Business, under the heading "Mining Operations."

Coal Reserves

We estimate that, as of December 31, 2006, we had total recoverable reserves of approximately 2.3 billion tons consisting of both proven and probable reserves. "Reserves" are defined by the SEC Industry Guide 7 as that part of a mineral deposit, which could be economically and legally extracted or produced at the time of the reserve determination. "Recoverable" reserves means coal that is economically recoverable using existing equipment and methods under federal and state laws currently in effect. Approximately 1.5 billion tons of reserves are classified as proven reserves. "Proven (measured) reserves" are defined by the SEC Industry Guide 7 as 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. The remaining 0.8 billion tons of our reserves are classified as probable reserves. "Probable reserves" are defined by the SEC Industry Guide 7 as reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling, and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our internal engineers, geologists and finance associates. Reserve estimates are updated annually using geologic data taken from drill holes, adjacent mine workings, outcrop prospect openings and other sources. Coal tonnages are categorized according to coal quality, seam thickness, mineability and location relative to existing mines and infrastructure. In accordance with applicable industry standards, proven reserves are those for which reliable data points are spaced no more than 2,700 feet apart. Probable reserves are those for which reliable data points are spaced 2,700 feet to 7,900 feet apart. Further scrutiny is applied using geological criteria and other factors related to profitable extraction of the coal. These criteria include seam height, roof and floor conditions, yield and marketability.

As with most coal-producing companies in Central Appalachia, the majority of our coal reserves are controlled pursuant to leases from third party landowners. These leases convey mining rights to the coal producer in exchange for a per ton or percentage of gross sales price royalty payment to the lessor. However, approximately 17% of our reserve holdings are owned and require no royalty or per ton payment to other parties. Royalty expense for coal reserves from our producing properties (owned and leased) was approximately 4.2% of Produced coal revenue for the year ended December 31, 2006.

The following table provides proven and probable reserve data by "status" (i.e., location, owned or leased, assigned or unassigned, etc.) as of December 31, 2006:

Resource Group	Location [2]	Recoverable Reserves [1] Total	Proven	Probable	Assigned [3]	Unassigned [3]	Owned	Leased
		(In Thousands of Tons)						
West Virginia								
Black Castle	Boone County	97,777	66,951	30,826	43,548	54,229	522	97,255
Delbarton	Mingo County	287,518	120,442	167,076	142,020	145,498	25	287,493
Edwight	Raleigh County	10,728	10,728	-	10,728	-	-	10,728
Elk Run	Boone County	160,036	124,754	35,282	61,333	98,703	4,660	155,376
Endurance	Boone County	27,052	27,052	-	27,052	-	25,780	1,272
Green Valley	Nicholas County	6,569	6,569	-	6,569	-	-	6,569
Independence	Boone County	58,569	53,213	5,356	41,628	16,941	9,035	49,534
Kepler	Wyoming County	43,617	15,266	28,351	-	43,617	330	43,287
Logan County	Logan County	79,479	66,507	12,972	53,713	25,766	-	79,479
Mammoth	Kanawha County	87,688	69,728	17,960	74,271	13,417	45,941	41,747
Marfork	Raleigh County	105,445	103,083	2,362	73,131	32,314	738	104,707
Nicholas Energy	Nicholas County	97,562	80,945	16,617	55,156	42,406	47,909	49,653
Progress	Boone County	22,896	17,018	5,878	22,896	-	-	22,896
Rawl	Mingo County	98,636	67,983	30,653	60,753	37,883	1,333	97,303
Republic Energy	Raleigh County	36,571	32,912	3,659	36,571	-	-	36,571
Stirrat	Logan County	5,293	3,476	1,817	412	4,881	-	5,293
Kentucky								
Coalgood Energy	Harlan County	19,572	10,668	8,904	1,235	18,337	2,704	16,868
Long Fork	Pike County	4,964	2,764	2,200	264	4,700	-	4,964
Martin County	Martin County	42,718	29,558	13,160	3,364	39,354	1,336	41,382
New Ridge	Pike County	-	-	-	-	-	-	-
Sidney	Pike County	131,463	77,483	53,980	106,152	25,311	7,304	124,159
Virginia								
Knox Creek	Tazewell County	45,809	33,653	12,156	30,076	15,733	-	45,809
Subtotal		1,469,962	1,020,753	449,209	850,872	619,090	147,617	1,322,345
Land Management Companies: [4]								
Black King	Boone County, WV	33,084	33,084	-	349	32,735	16,273	16,811
	Raleigh County, WV							
Boone East	Boone County, WV	130,535	96,529	34,006	4,570	125,965	58,461	72,074
	Kanawha County, WV							
Boone West	Lincoln County, WV	252,332	98,556	153,776	-	252,332	65,553	186,779
	Logan County, WV							
Ceres Land	Raleigh County, WV	33,351	24,220	9,131	-	33,351	-	33,351
Duncan Fork	Various counties, PA	65,728	30,791	34,937	-	65,728	65,728	-
Lauren Land	Mingo County, WV	175,278	116,003	59,275	-	175,278	18,311	156,967
	Logan County, WV							
	Various counties, KY							
New Market Land	Wyoming County, WV	7,984	4,606	3,378	-	7,984	102	7,882
Raven Resources	Raleigh County, WV	18,978	18,978	-	-	18,978	-	18,978
	Boone County, WV							
Tennessee Consolidated Coal	Various counties, TN	26,907	1,332	25,575	-	26,907	24,054	2,853
Subtotal		744,177	424,099	320,078	4,919	739,258	248,482	495,695
Other	N/A	59,000	38,716	20,284	-	59,000	1,288	57,712
Total		2,273,139	1,483,568	789,571	855,791	1,417,348	397,387	1,875,752

(1) Recoverable reserves represent the amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods under current law.

(2) All of the recoverable reserves listed are in Central Appalachia, except for the Duncan Fork reserves, which are located in Northern Appalachia and Lauren Land reserves, a portion of which are located in the Illinois Basin. The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserves of that Resource Group. The moisture factor represents the average moisture present in our delivered coal.

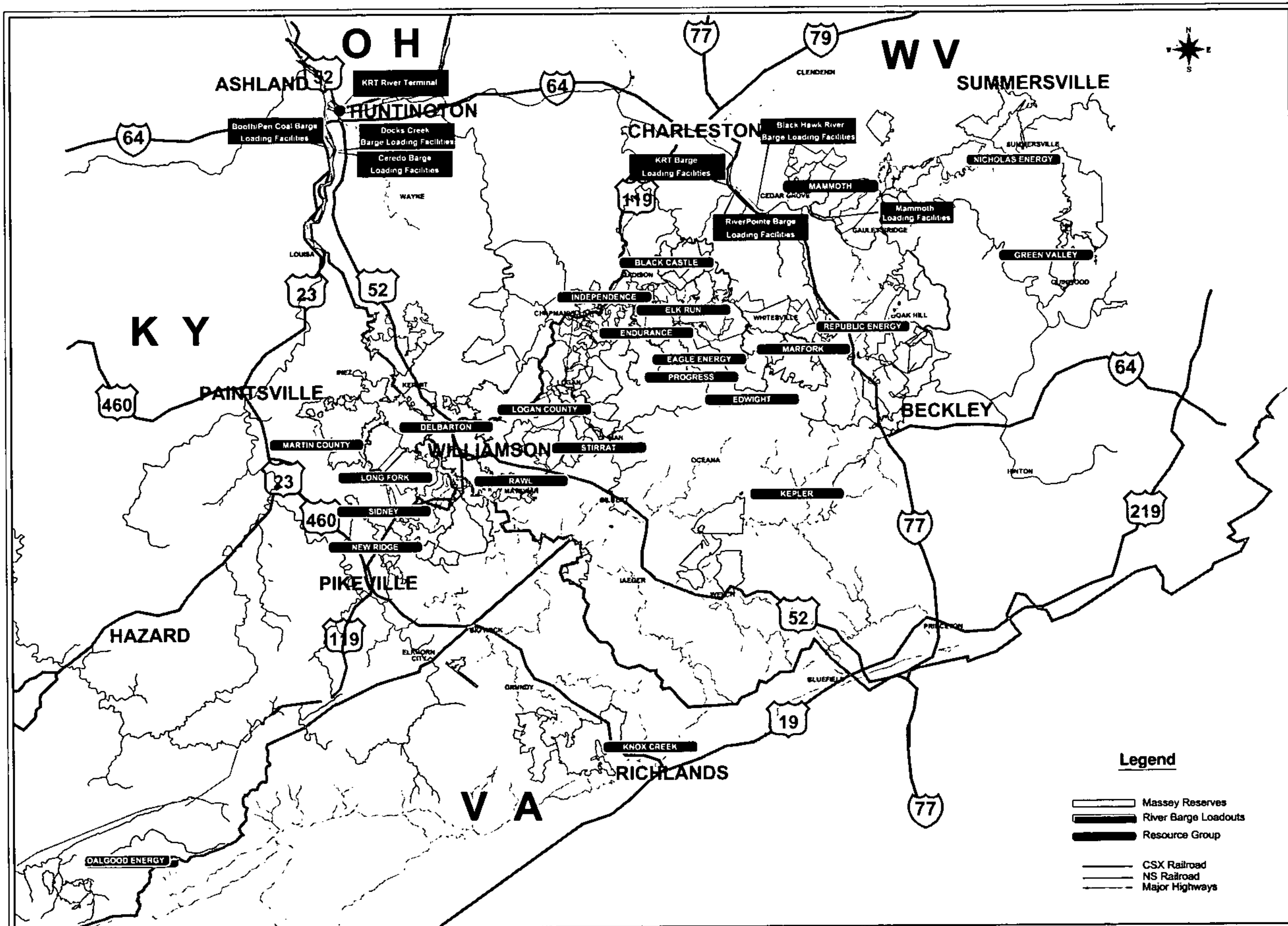
(3) Assigned Reserves represent recoverable reserves that are dedicated to a specific permitted mine; otherwise, the reserves are considered Unassigned. For Land Management Companies, Assigned Reserves have been leased to a third party and are dedicated to a specific permitted mine of the lessee.

(4) Land management companies are our subsidiaries whose primary purposes are to acquire and hold our reserves.

The categorization of the "quality" (i.e., sulfur content, Btu, coal type, etc.) of coal reserves is as follows:

	Recoverable Reserves	Recoverable Reserves [1] Sulfur content +1% [2]	-1% [2]	Compliance [3]	Avg.Btu as received [4]	Coal Type [5]
	(In Thousands of Tons Except Average Btu as Received)					
Resource Groups:						
West Virginia						
Black Castle	97,777	32,690	65,087	26,284	12,000	Utility and Industrial
Delbarton	287,518	111,954	175,564	127,073	12,500	High Vol Met, Utility, and Industrial
Edwight	10,728	1,574	9,154	8,716	12,800	High Vol Met, Utility, and Industrial
Elk Run	160,036	76,309	83,727	74,978	13,400	High Vol Met, Utility, and Industrial
Endurance	27,052	5,061	21,991	12,657	12,500	Utility and Industrial
Green Valley	6,569	-	6,569	5,223	13,100	High Vol Met, Utility, and Industrial
Independence	58,569	12,834	45,735	8,462	13,100	High Vol Met, Utility, and Industrial
Kepler	43,617	-	43,617	43,617	13,800	Low Vol Met
Logan County	79,479	22,848	56,631	46,369	12,500	High Vol Met, Utility, and Industrial
Mammoth	87,688	5,859	81,829	36,058	12,000	Utility and Industrial
Marfork	105,445	51,085	54,360	33,404	13,150	High Vol Met, Utility, and Industrial
Nicholas Energy	97,562	40,519	57,043	25,088	11,800	Utility and Industrial
Progress	22,896	2,163	20,733	19,168	12,400	High Vol Met, Utility, and Industrial
Rawl	98,636	30,528	68,108	85,790	12,600	High Vol Met, Utility, and Industrial
Republic	36,571	5,531	31,040	21,048	12,400	High Vol Met and Utility
Stirrat	5,293	-	5,293	5,293	13,800	High Vol Met, Utility, and Industrial
Kentucky						
Coalgood Energy	19,572	4,637	14,935	10,360	11,900	High Vol Met, Utility, and Industrial
Long Fork	4,964	3,500	1,464	-	12,500	Utility and Industrial
Martin County	42,718	31,939	10,779	3,042	12,000	Utility and Industrial
New Ridge	-	-	-	-	-	N/A
Sidney	131,463	52,163	79,300	56,856	12,500	High Vol Met, Utility, and Industrial
Virginia						
Knox Creek	45,809	-	45,809	45,809	13,300	High Vol Met, Utility, and Industrial
Subtotal	1,469,962	491,194	978,768	695,295		
Land Management Companies: [6]						
Black King	33,084	15,570	17,514	14,367	13,300	High Vol Met and Utility
Boone East	130,535	33,190	97,345	32,978	13,100	High Vol Met, Utility, and Low Vol Me
Boone West	252,332	134,076	118,256	79,369	13,100	High Vol Met and Utility
Ceres Land	33,351	5,991	27,360	12,740	13,000	High Vol Met and Utility
Duncan Fork	65,728	65,728	-	-	13,600	High Vol Met, Utility, and Industrial
Lauren Land	175,278	79,191	96,087	73,087	12,400	High Vol Met and Utility
New Market Land	7,984	-	7,984	7,984	13,600	High Vol Met and Low Vol Met
Raven Resources	18,978	9,001	9,977	1,393	13,100	High Vol Met and Utility
Tennessee Consolidated Coal	26,907	20,353	6,554	4,816	12,800	High Vol Met, Utility and Industrial
Subtotal Land Management	744,177	363,100	381,077	226,734		
Other	59,000	6,813	52,187	47,679	13,000	Various
Total	2,273,139	861,107	1,412,032	969,708		

(1) The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserves of that Resource Group. The moisture factor represents the average moisture present in our delivered coal.
(2) +1% or -1% refers to sulfur content as a percentage in coal by weight. Compliance coal is less than 1% sulfur content by weight and is included in the -1% column.
(3) Compliance coal is any coal that emits less than 1.2 pounds of sulfur dioxide per million Btu when burned. Compliance coal meets sulfur emission standards imposed by Title IV of the Clean Air Act.
(4) Represents an estimate of the average Btu per pound present in our coal, as it is received by the customer.
(5) Reserve holdings include metallurgical coal reserves. Although these metallurgical coal reserves receive the highest selling price in the current coal market when marketed to steel-making customers, they can also be marketed as an ultra high Btu, low sulfur utility coal for electricity generation.
(6) Land management companies are our subsidiaries whose primary purposes are to acquire and hold our reserves.



MASSEY ENERGY PROPERTIES
JANUARY 2007

Note: Other coal reserve holdings not shown on this map include those located in Fayette and Westmoreland Counties, Pennsylvania, Daviess and McLean Counties, Kentucky and in Marion, Sequatchie, and Grundy Counties, Tennessee.

SCALE: 1" = 17.33 Miles

10 0 10 20 30

Item 3. Legal Proceedings

Martin County Impoundment Discharge

On October 11, 2000, a partial failure of the coal refuse impoundment of Martin County Coal Corporation, one of our subsidiaries, released approximately 250 million gallons of coal slurry into two tributary streams of the Big Sandy River in eastern Kentucky. On May 30, 2006, the Federal Mine Safety and Health Review Commission remanded citations and penalties issued by MSHA initially totaling approximately $110,000, subsequently reduced to $5,500 by an administrative law judge ("ALJ"), to a new ALJ for further consideration. In January 2007, a new hearing was held before the new ALJ. We believe these items will be resolved without a material impact on our cash flows, results of operations or financial condition.

Valley Fill Litigation

Since September 2005, three environmental groups sued the U.S. Army Corps of Engineers ("Corps") in the United States District Court for the Southern District of West Virginia, asserting that permits to construct valley fills were issued unlawfully to five of our surface mines. The suit alleges that the Corps failed to comply with the requirements of both Section 404 of the Clean Water Act and the National Environmental Policy Act, including preparing environmental impact statements for individual permits. We intervened in the suit to protect our interests. Trial was held in October and November 2006. If the Court finds that the permits are unlawful, production could be materially affected at these surface mines and the process of obtaining Corps permits for all surface mines could become more difficult.

Other Legal Proceedings

Certain information regarding other legal proceedings required by this Item 3 is contained in Note 17, "Contingencies and Commitments," to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K and is incorporated herein by reference.

We are parties to a number of other legal proceedings, incident to our normal business activities. These matters include contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition.

We are also party to lawsuits and other legal proceedings related to the non-coal businesses previously conducted by Fluor Corporation (renamed Massey Energy Company) but now conducted by New Fluor. Under the terms of the Distribution Agreement entered into by New Fluor and us as of November 30, 2000, in connection with the Spin-Off of New Fluor by the Company, New Fluor agreed to indemnify us with respect to all such legal proceedings and has assumed their defense.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders through a solicitation of proxies or otherwise during the fourth quarter of the fiscal year ended December 31, 2006.

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock

Common Stock is listed on the New York Stock Exchange ("NYSE") and trades under the symbol MEE. As of February 15, 2007, there were 81,068,790 shares outstanding and approximately 7,300 shareholders of record of Common Stock.

The following table sets forth the high and low sales prices per share of Common Stock on the NYSE for the past two years, based upon published financial sources, and the dividends declared on each share of Common Stock for the quarter indicated.

	High	Low	Dividends
Fiscal Year 2005			
Quarter ended March 31, 2005	$ 46.60	$ 31.80	$ 0.04
Quarter ended June 30, 2005	$ 42.15	$ 34.86	$ 0.04
Quarter ended September 30, 2005	$ 57.00	$ 37.76	$ 0.04
Quarter ended December 31, 2005	$ 52.59	$ 36.62	$ 0.04
Fiscal Year 2006			
Quarter ended March 31, 2006	$ 41.53	$ 33.10	$ 0.04
Quarter ended June 30, 2006	$ 44.34	$ 32.15	$ 0.04
Quarter ended September 30, 2006	$ 37.05	$ 18.77	$ 0.04
Quarter ended December 31, 2006	$ 28.00	$ 19.31	$ 0.04

Dividends

On February 20, 2007, our board of directors declared a dividend of $0.04 per share, payable on April 10, 2007, to shareholders of record on March 27, 2007.

Our current dividend policy anticipates the payment of quarterly dividends in the future. We are restricted by our asset-based revolving credit facility, our 6.625% senior notes due 2010 (the "6.625% Notes") and our 6.875% senior notes due 2013 (the "6.875% Notes") from paying dividends in excess of $25 million annually on Common Stock, and then only so long as no default exists under the facility, the 6.625% Notes, or the 6.875% Notes, as the case may be, or would result thereunder from paying such dividend. There are no other restrictions, other than those set forth under the corporate laws of the State of Delaware, where we are incorporated, on our ability to declare and pay dividends. The declaration and payment of dividends to holders of Common Stock will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, and capital requirements.

Convertible Debt Securities

Our 4.75% convertible senior notes due 2023 (the "4.75% Notes") are convertible by holders into shares of Common Stock during certain periods under certain circumstances. As of December 31, 2006, the price of Common Stock had reached the specified threshold for conversion. Consequently, the 4.75% Notes are convertible until March 31, 2007, the last day of our first quarter. The 4.75% Notes may be convertible beyond this date if the specified threshold for conversion is met in subsequent quarters. In August 2006, $20,000 of principal amount of the 4.75% Notes was converted into 1,031 shares of Common Stock. No other conversions occurred during 2006. If all of the notes outstanding at December 31, 2006 had been converted, we would have needed to issue 37,649 shares of Common Stock. In addition, holders of the 4.75% Notes may require us to purchase all or a portion of their 4.75% Notes on May 15, 2009, May 15, 2013, and May 15, 2018. For purchases on May 15, 2013 or May 15, 2018, we may, at our option, choose to pay the purchase price in cash or in shares of Common Stock or any combination thereof. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of the conversion and redemption features of the 4.75% Notes.

Our 2.25% convertible senior notes due 2024 (the "2.25% Notes") are convertible by holders into shares of Common Stock during certain periods under certain circumstances. None of the 2.25% Notes were eligible for conversion at December 31, 2006. If all of the notes outstanding at December 31, 2006 had been eligible and were converted, we would have needed to issue 287,113 shares of Common Stock. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of conversion features of the 2.25% Notes.

Repurchase Program

On November 14, 2005, our Board of Directors authorized a stock repurchase program (the "Repurchase Program"), authorizing us to repurchase shares of Common Stock. We may repurchase Common Stock from time to time, as determined by authorized officers, up to an aggregate amount not to exceed $500 million (excluding commissions) with free cash flow as existing financing covenants may permit. Existing covenants currently allow for up to approximately $18.5 million of share repurchases. The stock repurchases may be conducted on the open market, through privately negotiated transactions, through derivative transactions or through purchases made in accordance with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended ("Exchange Act"), in compliance with the SEC's regulations and other legal requirements. The Repurchase Program does not require us to acquire any specific number of shares and may be terminated at any time. On April 24, 2006, our Board of Directors amended the program to allow share repurchases of up to $50 million using cash currently on hand. Share repurchases of $50 million using cash on hand were completed on June 8, 2006, with the purchase of 1.3 million shares of Common Stock at an average price of $38.47 per share. No additional share repurchases have been made since that time. All shares repurchased under the program have been recorded as Treasury stock.

Transfer Agent and Registrar

The transfer agent and registrar for Common Stock is Wells Fargo Shareowner Services, 161 North Concord Exchange, South St. Paul, Minnesota 55075, toll free (800) 689-8788.

Item 6. Selected Financial Data

SELECTED FINANCIAL DATA[1]

	2006	2005	2004	2003	2002
	Year Ended December 31, (In millions, except per share, per ton, and number of employees amounts)				
CONSOLIDATED STATEMENT OF INCOME DATA:					
Produced coal revenue	$ 1,902.3	$ 1,777.7	$ 1,456.7	$ 1,262.1	$ 1,318.9
Total revenue	2,219.9	2,204.3	1,766.6	1,571.4	1,630.1
Income (Loss) before interest and income taxes	111.0	(20.9)	46.2	(17.5)	(26.7)
Income (Loss) before cumulative effect of accounting change	41.6	(101.6)	13.9	(32.3)	(32.6)
Net income (loss)	41.0	(101.6)	13.9	(40.2)	(32.6)
Income (Loss) per share - Basic [1]					
Income (Loss) before cumulative effect of accounting change	$ 0.51	$ (1.33)	$ 0.18	$ (0.43)	$ (0.44)
Net income (loss)	$ 0.50	$ (1.33)	$ 0.18	$ (0.54)	$ (0.44)
Income (Loss) per share - Diluted [1]					
Income (Loss) before cumulative effect of accounting change	$ 0.51	$ (1.33)	$ 0.18	$ (0.43)	$ (0.44)
Net income (loss)	$ 0.50	$ (1.33)	$ 0.18	$ (0.54)	$ (0.44)
Dividends declared per share	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
CONSOLIDATED BALANCE SHEET DATA:					
Working capital (deficit)	$ 445.2	$ 670.8	$ 458.4	$ 443.2	$ (59.7)
Total assets	2,740.7	2,986.5	2,650.9	2,376.7	2,241.4
Long-term debt	1,102.3	1,102.6	900.2	784.3	286.0
Shareholders' equity [2]	697.3	841.0	776.9	759.0	808.2
OTHER DATA:					
EBIT [3]	$ 111.0	$ (20.9)	$ 46.2	$ (17.5)	$ (26.7)
EBITDA [3]	$ 341.5	$ 213.6	$ 270.8	$ 179.0	$ 181.0
Average cash cost per ton sold [4]	$ 42.33	$ 35.62	$ 30.50	$ 28.23	$ 28.64
Produced coal revenue per ton sold	$ 48.71	$ 42.02	$ 36.02	$ 30.79	$ 31.30
Capital expenditures	$ 298.1	$ 346.6	$ 347.2	$ 164.4	$ 135.1
Produced tons sold	39.1	42.3	40.4	41.0	42.1
Tons produced	38.6	43.1	42.0	41.0	43.9
Number of employees	5,517	5,709	5,034	4,428	4,552

(1) In accordance with accounting principles generally accepted in the U.S. ("GAAP"), the effect of dilutive securities was excluded from the calculation of the diluted (loss) income per common share for the years ended December 31, 2006, 2005, 2004, 2003, and 2002, as such inclusion would result in antidilution.

(2) Certain accounting pronouncements adopted in 2006 affect the comparability of the 2006 financial statements to prior years. The adoption of Emerging Issues Task Force Issue No. 04-6, "Accounting for Stripping Costs Incurred During Production in the Mining Industry" on January 1, 2006 decreased equity by $93.8 million (see Note 2 to the Notes to Consolidated Financial Statements for more information) and the adoption of SFAS No. 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" on December 31, 2006 decreased equity by $40.2 million (see Notes 5, 10 and 11 to the Notes to Consolidated Financial Statements for more information).

(3) EBIT is defined as Income (Loss) before interest and taxes. EBITDA is defined as Income (Loss) before interest and taxes before deducting Depreciation, depletion, and amortization ("DD&A"). Although EBITDA is not a measure of performance calculated in accordance with GAAP, we believe that it is useful to an investor in evaluating us because it is widely used in the coal industry as a measure to evaluate a company's operating performance before debt expense and as a measure of its cash flow. EBITDA does not purport to represent operating income, net income or cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance in accordance with GAAP. In addition, because EBITDA is not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Income (Loss) before interest and taxes to EBITDA. For the year ended December 31, 2005, EBIT and EBITDA include charges related to our capital restructuring of $212.4 million.

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In millions)				
Income (Loss) before interest and income taxes	$111.0	$ (20.9)	$ 46.2	$ (17.5)	$ (26.7)
Depreciation, depletion and amortization	230.5	234.5	224.6	196.5	207.7
EBITDA	$341.5	$213.6	$270.8	$179.0	$181.0

(4) Average cash cost per ton is calculated as the sum of Cost of produced coal revenue and Selling, general and administrative expense ("SG&A") (excluding DD&A), divided by the number of produced tons sold. Although Average cash cost per ton is not a measure of performance calculated in accordance with GAAP, we believe that it is useful to investors in evaluating us because it is widely used in the coal industry as a measure to evaluate a company's control over its cash costs. Average cash cost per ton should not be considered in isolation or as a substitute for measures of performance in accordance with GAAP. In addition, because Average cash cost per ton is not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Total costs and expenses to Average cash cost per ton.

	Year Ended December 31,									
	2006		2005		2004		2003		2002	
	(In millions, except per ton amounts)									
	$	per ton	$	per ton	$	per ton	$	per ton	$	per ton
Total costs and expenses	$2,108.8		$2,225.2		$1,720.4		$1,588.9		$1,656.8	
Less: Freight and handling costs	156.5		150.9		148.8		109.7		112.0	
Less: Cost of purchased coal revenue	62.6		112.6		104.1		117.3		119.6	
Less: Depreciation, depletion and amortization	230.5		234.5		224.6		196.5		207.7	
Less: Other expense	6.2		8.0		9.5		9.8		11.2	
Less: Loss on capital restructuring	-		212.4		-		-		-	
Average cash cost	$1,653.0	$42.33	$1,506.8	$35.62	$1,233.4	$30.50	$1,155.6	$28.23	$1,206.3	$28.64

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Executive Overview

We operate coal mines and processing facilities in Central Appalachia, which generate revenues and cash flow through the mining, processing and selling of steam and metallurgical grade coal, primarily of a low sulfur content. We also generate income and cash flow through other coal-related businesses, including the management of material handling facilities and a synfuel production plant. Other revenue is obtained from royalties, rentals, gas well revenues, gains on the sale of non-strategic assets, and miscellaneous income. For the year ended December 31, 2006, approximately 71% of produced tons sold were to U.S. electricity generators, 20% were to steel manufacturers in the U.S. and abroad, and 9% were to the U.S. industrial sector.

We reported net income for the year ended December 31, 2006 of $41.0 million, or $0.50 per basic share, compared to net loss for 2005 of $101.6 million, or $1.33 per basic share. Net income in 2006 included pre-tax gains totaling approximately $30 million ($19 million after-tax or $0.24 per diluted share) related to the sale of our Falcon reserves. Included in the 2005 loss was an after-tax charge of $216.2 million, or $2.83 per basic share related to a capital restructuring. Results in 2005 also included gains totaling approximately $57.3 million after-tax or $0.74 per basic share related to the sale of our ownership interest in the property known as Big Elk Mining Company and a non-cash exchange of coal reserves.

Produced tons sold were 39.1 million in 2006, compared to 42.3 million in 2005. Shipments were negatively affected during the year by productivity issues at underground mines, including the loss of six months of production from our Logan County resource group's Aracoma longwall mine due to a fire in January 2006 and geological difficulties at several underground mines, especially at our Revolution and Rockhouse longwall mines (located at our Independence and Sidney resource groups, respectively). We also continued to experience railroad congestion due to heightened coal demand and a lack of rail cars and a tight labor market that lead to high turnover and inexperienced workers. We produced 38.6 million tons during 2006, compared to 43.1 million tons produced in 2005. Exports decreased to 4.2 million tons compared to 5.3 million tons exported in 2005. In an effort to better manage our production in 2006 to adjust to the changing coal markets, we closed several low-margin coal mines, including our Rockhouse longwall and replaced some of the production capacity by adding a dragline at our Twilight surface mine and purchasing new, more productive surface and underground mine equipment.

During 2006, Produced coal revenue increased by 7% over the prior year on fewer tons shipped as we benefited from higher prices secured in new agreements as lower-priced contracts expired. These higher priced contracts were negotiated during a period of strong economic growth in China, India, the U.S. and other regions of the world, during which a worldwide shortage of certain grades of coal existed, stockpile inventories at utilities were low, and the cost of natural gas and oil was high. As 2006 progressed, spot coal prices dropped as a warm winter and relatively mild summer weather in the U.S. allowed utilities to rebuild their stockpiles and lowered the price of natural gas, resulting in natural gas storage injections that reached record levels. Our average Produced coal revenue per ton sold in 2006 increased by 16% to $48.71 compared to $42.02 in 2005 and by 56% over a five-year period compared to $31.30 in 2002. Our average Produced coal revenue per ton in 2006 for metallurgical tons sold increased by 28% to $69.20 from $54.19 in 2005.

We experienced a significant increase in costs during the past 5-year period, with Average cash cost per ton sold increasing from $28.64 in fiscal 2002 to $42.33 in fiscal 2006 (a reconciliation of these non-GAAP figures is presented in footnote 3 of Item 6. Selected Financial Data). The increased cost level is mainly due to increased sales-related costs resulting from the growth in average per ton realization, materially higher supply costs, including diesel fuel, steel, copper and explosives, higher labor and benefit costs, and lower operating productivity, as discussed above.

In June 2006, Congress passed and President Bush signed the MINER Act, which, among other things, requires mine-specific emergency response plans, enhanced communication systems, and more available mine rescue teams, as well as larger penalties by MSHA for noncompliance by mine operators. In December 2006, MSHA similarly passed its final rule on Emergency Mine Evacuation, which includes requirements for increased availability and storage of SCSRs; improved emergency evacuation drills and SCSR training; and the installation and maintenance of lifelines in underground coal mines. Coal producing states, including West Virginia and Kentucky, passed similar legislation in 2006. While the full cost of compliance remains unknown, we spent over $3 million in 2006 and estimate that we will spend a total of $20 million to $25 million over two to three years to fully comply with these laws. These costs were capitalized in Net Property, Plant and Equipment for 2006.

Results of Operations

2006 Compared with 2005

Revenues

For the year ended December 31, 2006, produced coal revenue increased $124.6 million, or 7%, to $1,902.3 million compared with $1,777.7 million for the year ended December 31, 2005. The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2006 compared to 2005:

	Year Ended December 31,			
(In millions, except per ton amounts)	2006	2005	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	27.7	29.2	(1.5)	(5)%
Metallurgical	7.8	9.4	(1.6)	(17)%
Industrial	3.6	3.7	(0.1)	(3)%
Total	39.1	42.3	(3.2)	(8)%
Produced coal revenue per ton sold:				
Utility	$42.37	$36.66	$5.71	16%
Metallurgical	69.20	54.19	15.01	28%
Industrial	53.13	53.19	(0.06)	0%
Weighted average	48.71	42.02	6.69	16%

The improvement in our average per ton sales price was attributable to prices contracted during a period of increased demand for all grades of coal in the U.S. and for metallurgical coal worldwide, as our lower-priced sales contracts expired. Increased prices for alternative fuel sources such as oil and natural gas also resulted in higher demand for certain coals. Exports of metallurgical coal decreased by 1.0 million tons, or 19%, to 4.2 million tons for 2006 as compared to 2005 due to lower production.

Freight and handling revenue increased $5.6 million, or 4%, to $156.5 million for 2006 compared with $150.9 million for 2005, due to more shipments to customers where we paid for freight and handling.

Purchased coal revenue decreased $61.7 million, or 47%, to $70.6 million for 2006 from $132.3 million for 2005, mainly due to a decrease in purchased tons sold from 2.5 million in 2005 to 1.3 million in 2006, offset by a 3% increase in revenue per ton. We purchase varying amounts of coal to supplement produced coal sales.

Other revenue, which consists of royalties, rentals, earnings associated with coal handling facilities, gas well revenues, synfuel earnings, gains on the sale of non-strategic assets, contract settlement payments, and miscellaneous income, decreased $52.9 million, or 37%, to $90.4 million for 2006 from $143.3 million for 2005. Other revenue for 2006 includes a pre-tax gain of $30.0 million on the sale of our Falcon reserves (see Note 4 in the Notes to Condensed Consolidated Financial Statements for further discussion). Other revenue for 2005 includes a pre-tax gain of $45.9 million related to the sale of our ownership interest in Big Elk Mining Company and a pre-tax gain of $38.2 million on a coal reserves exchange (see Note 4 in the Notes to Condensed Consolidated Financial Statements for further discussion).

Costs

Cost of produced coal revenue increased approximately 11% to $1,599.1 million for 2006 from $1,438.5 million for 2005. Cost of produced coal revenue on a per ton of coal sold basis increased 19% in 2006 compared with 2005. This increase resulted from a variety of factors including higher labor and benefit costs, higher supply costs, including diesel fuel, explosives, copper and steel prices, productivity issues at several underground mines, including the Revolution and Rockhouse longwall mines, and difficulties encountered in the restart of the Aracoma mine in July 2006. A fire at the Aracoma mine, which occurred in January 2006, also contributed significantly to the increase in Cost of produced coal revenue. Also negatively impacting Cost of produced coal revenue were higher sales-related costs for production royalties and taxes, and severance and black lung excise taxes associated with the increase in average realized prices. Tons produced during 2006 were 38.6 million compared to 43.1 million during 2005.

Freight and handling costs increased $5.6 million, or 4%, to $156.5 million for 2006 compared with $150.9 million for 2005, due to more shipments to customers where we pay freight and handling.

Cost of purchased coal revenue decreased $50 million, or 44%, to $62.6 million for 2006 from $112.6 million for 2005, due to a slight decrease in purchased tons sold from 2.5 million in 2005 to 1.3 million in 2006, offset by a 7% increase in average cost of purchased coal per ton.

Depreciation, depletion and amortization decreased $4.1 million, or 2%, to $230.5 million in 2006 compared to $234.6 million in 2005.

Selling, general and administrative expenses decreased $14.5 million, or 21%, to $53.8 million for 2006 compared to $68.3 million for 2005. The decrease was primarily attributable to lower stock-based compensation accruals due to changes in the price of the Company's stock and lower performance-linked executive compensation accruals in 2006.

Other expense, which consists of costs associated with the generation of other revenue, such as costs to operate the coal handling facilities, gas wells, and other miscellaneous expenses, decreased from $8.0 million in 2005 to $6.2 million in 2006.

Interest

Interest income of $20.1 million in 2006 was greater than the $12.6 million earned in 2005 due to higher levels of cash reserves during 2006 and higher interest rates received on investments during 2006. Interest expense increased to $86.1 million for 2006 compared with $67.1 million for 2005. The higher interest expense was primarily a result of a debt restructuring that occurred in December 2005, which increased debt levels in 2006 compared to 2005, and resulted in a higher effective interest rate. Interest expense in 2005 included a $6.6 million write-off of previously unamortized debt issuance costs related to our debt restructuring.

Income Taxes

Income tax expense was $3.4 million for 2006 compared with a tax expense of $26.2 million for 2005. The income tax rate for 2006 was favorably impacted by percentage depletion allowances, the usage of a net operating loss carryforward and the adjustment of reserves in connection with the closing of a prior period audit by the IRS. The income tax rate for 2005 was negatively impacted by the non-deductibility on the early payout of deferred compensation ($7.5 million tax effect) and the non-deductibility on our debt repurchases and exchange offers during the fourth quarter. The tax rate for 2005 was favorably impacted by percentage depletion allowances, the usage of a net operating loss carry forward, the adjustment of reserves in connection with the closing of a prior period audit by state taxing authorities and the IRS and the closing of a federal statutory period. Because of the tax benefit recognized as a result of the closing of the statutory periods and other factors, the tax rate for 2005 and 2006 should not be considered indicative of future tax rates.

2005 Compared with 2004

Revenues

For the year ended December 31, 2005, produced coal revenue increased $321.0 million, or 22%, to $1,777.7 million compared with $1,456.7 million for the year ended December 31, 2004. The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2005 compared to 2004:

(In millions, except per ton amounts)	Year Ended December 31, 2005	2004	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	29.2	25.7	3.5	14%
Metallurgical	9.4	10.4	(1.0)	(1)%
Industrial	3.7	4.3	(0.6)	(14)%
Total	42.3	40.4	1.9	5%
Produced coal revenue per ton sold:				
Utility	$36.66	$31.79	$4.87	15%
Metallurgical	54.19	45.55	8.64	19%
Industrial	53.19	38.21	14.98	39%
Weighted average	42.02	36.02	6.00	17%

The improvement in our average per ton sales price was attributable to a continuing global economic recovery, rapid economic expansion in China, and increased prices for alternative fuel sources such as oil and natural gas that resulted in shortages of certain coals and led to increases in the market prices of these coals. We were able to take advantage of the market situation during 2005 by negotiating higher prices as lower-priced sales contracts expired. Our exports of metallurgical coal decreased by 1.0 million tons, or 16%, to 5.1 million tons for 2005 as compared to 2004 due to lower production.

Freight and handling revenue increased $2.1 million, or 1%, to $150.9 million for 2005 compared with $148.8 million for 2004, due to more shipments to customers where we paid for freight and handling.

Purchased coal revenue increased $27.4 million, or 26%, to $132.3 million for 2005 from $104.9 million for 2004, mainly due to an 18% average increase in purchased coal revenue per ton. We purchase varying amounts of coal to supplement produced coal sales.

Other revenue, which consists of royalties, rentals, coal handling facility fees, gas well revenues, synfuel earnings, gains on the sale of non-strategic assets, and miscellaneous income, increased $87.1 million, or 155%, to $143.3 million for 2005 from $56.2 million for 2004. The increase was primarily due to $84.1 million related to the sale of our ownership interest in Big Elk Mining Company and a non-cash gain on the exchange of coal reserves.

Costs

Cost of produced coal revenue increased approximately 22% to $1,438.5 million for 2005 from $1,175.9 million for 2004. This increase resulted from a variety of factors including higher labor and supply costs, including diesel fuel, explosives and steel prices, productivity issues, and continuing costs to comply with regulatory requirements. Also negatively impacting cost of produced coal revenue were higher sales-related costs for production royalties and taxes associated with the increase in average realized prices. Tons produced during 2005, were 43.1 million compared to 42.0 million during 2004. As production was greater than shipped tons, coal inventories (in various stages of production) increased during 2005.

Freight and handling costs increased $2.1 million, or 1%, to $150.9 million for 2005 compared with $148.8 million for 2004, due to more shipments to customers where we paid for freight and handling.

Cost of purchased coal revenue increased $8.5 million, or 8%, to $112.6 million for 2005 from $104.1 million for 2004, due to a slight increase in purchased tons sold from 2.4 million in 2004 to 2.5 million in 2005, as well as a 1% increase in average cost of purchased coal per ton.

Depreciation, depletion and amortization increased $10.0 million, or 4%, to $234.6 million in 2005 compared to $224.6 million in 2004, due in part to a significant investment in new surface and underground mining equipment during 2005. DD&A in 2004 included the write-off of $6.1 million (pre-tax) of capitalized development costs at an idle mine and a gas well.

Selling, general and administrative expenses increased $10.8 million, or 19%, to $68.3 million for 2005 compared to $57.5 million for 2004. The increase was primarily attributable to higher stock-based compensation accruals based on the appreciation and higher average market price of Common Stock during 2005. In addition, SG&A in 2004 was positively impacted by a $4.3 million reduction in our bad debt reserves due to the re-evaluation of the total reserve, in light of improved market conditions for the steel industry and our tighter credit terms.

Other expense, which consists of costs associated with the generation of other revenue, such as costs to operate the coal handling facilities, gas wells, and other miscellaneous expenses, decreased from $9.5 million in 2004 to $8.0 million in 2005.

Interest

Interest income of $12.6 million in 2005 was greater than the $8.8 million earned in 2004 as we had higher levels of cash reserves on hand during 2005. Interest expense increased to $67.1 million for 2005 compared with $60.7 million for 2004. The higher interest expense was due in part to higher debt levels in 2005 compared to 2004 and to a $6.6 million write-off of previously unamortized debt issuance costs related to our debt restructuring during 2005.

Income Taxes

Income tax expense was $26.2 million for 2005 compared with a tax benefit of $19.5 million for 2004. The income tax rate for 2005 was negatively impacted by the non-deductibility on the early payout of deferred compensation ($7.5 million tax effect) and the non-deductibility on our debt restructuring during the fourth quarter. The tax rate for 2005 was favorably impacted by percentage depletion allowances and the adjustment of reserves in connection with the closing of a prior period audit by state taxing authorities and the closing of a federal statutory period. In 2004, the tax rate was favorably impacted by percentage depletion allowances, the closing of a prior period audit by the IRS, and the closing of a federal statutory period. In accordance with company policy, a reserve was released for the closed statutory periods. Because of the tax benefit recognized as a result of the closing of the statutory periods and other factors, the tax rate for 2005 and 2004 should not be considered indicative of future tax rates.

Liquidity and Capital Resources

At December 31, 2006, our available liquidity was $350.0 million, which consisted of cash and cash equivalents of $239.2 million and $110.8 million availability under the asset-backed liquidity facility.

Debt was comprised of the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 754,804	$ 754,277
6.625% senior notes due 2010	335,000	335,000
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	730	750
Capital lease obligations	11,232	21,443
Fair value hedge adjustment	(6,506)	(7,855)
Total debt	1,104,907	1,113,262
Amounts due within one year	(2,583)	(10,680)
Total long-term debt	$ 1,102,324	$ 1,102,582

Asset-Based Credit Facility

On August 15, 2006, we amended and restated our asset-based revolving credit agreement, which provides for available borrowings, including letters of credit, of up to $175 million, depending on the level of eligible inventory and accounts receivable. The previous credit limit was $130 million, including a $100 million sublimit for letters of credit. In addition, we achieved improved pricing and extended the facility's maturity to August 2011. As of December 31, 2006, there were $64.2 million of letters of credit issued and there were no outstanding borrowings under this facility.

Conversion of 4.75% Notes

In August 2006, $20,000 of principal amount of the 4.75% Notes was converted into 1,031 shares of Common Stock.

Debt Ratings

Moody's Investors Service ("Moody's") and Standard & Poor's Rating Services ("S&P") rate our long-term debt. As of December 31, 2006, our S&P outlook rating is Developing. Moody's outlook on all of our notes is Stable; our Corporate Family Rating is B1.

Current Ratings:	Moody's	S&P
6.875% Notes	B2	B+
6.625% Notes	B2	B+
2.25% Notes	B2	B+
4.75% Notes	B3	B-

Convertible Notes Threshold

Both the 4.75% Notes and 2.25% Notes are convertible by holders into shares of Common Stock during certain periods under certain circumstances. As of December 31, 2006, the price of Common Stock had reached the specified threshold for conversion for the 4.75% Notes. Consequently, the 4.75% Notes are convertible until March 31, 2007, the last day of our first quarter, however, the 2.25% Notes are not convertible during this period. The 4.75% Notes and the 2.25% Notes may be convertible in future periods if the specified threshold for conversion is met in subsequent quarters.

Cash Flow

Net cash provided by operating activities was $214.5 million for 2006 compared to $270.1 million for 2005. Cash provided by operating activities reflects Net (loss) income adjusted for non-cash charges and changes in working capital requirements. In 2005, coal inventory increased by $85.9 million, mainly due to an increase of $55.8 million in Saleable coal (see Note 2 to the Notes to Consolidated Financial Statements for further discussion). Changes in deposits and inventory are included in Changes in operating assets and liabilities.

Net cash utilized by investing activities was $246.7 million and $273.0 million for 2006 and 2005, respectively. The cash used in investing activities reflects capital expenditures in the amount of $298.1 million and $346.6 million for 2006 and 2005, respectively. These capital expenditures are for replacement of mining equipment, the expansion of mining and shipping capacity, and projects to improve the efficiency of mining operations. Included in these capital expenditures are $25.3 million and $13.8 million of cash spent for the buyout of operating leases in 2006 and 2005, respectively. Additionally, 2006 and 2005 included $51.5 million and $73.5 million, respectively, of proceeds provided by the sale of assets. Proceeds from the sale of assets for 2006 included $30.8 million in cash related to the sale of our Falcon reserves (see Note 4 to the Notes to Consolidated Financial Statements for further discussion). Proceeds from the sale of assets for 2005 include $49.0 million for the sale of our ownership interest in Big Elk Mining Company to a privately held coal company (see Note 4 to the Notes to Consolidated Financial Statements for further discussion).

Financing activities primarily reflect changes in debt levels for 2006 and 2005, as well as the exercising of stock options and payments of dividends. Net cash utilized by financing activities was $48.0 million for 2006 while net cash provided by financing activities was $199.8 million for 2005. Net cash provided by financing activities for 2005 includes the proceeds of $742.8 million (after discount and fees) from the issuance of the 6.875% Notes, offset by the cash utilized for the debt repurchases and exchange offer of $562.6 million. Additionally, during 2005, we made open-market debt repurchases, retiring a total principal amount of $19.1 million of the 6.95% Notes at a cost of $19.8 million, plus accrued interest. Financing activities for 2006 included $50.0 million for the repurchase of 1.3 million shares of Common Stock under the share repurchase program discussed below. We generated $21.8 million from several sale-leaseback (operating leases) transactions of certain mining equipment in 2006, compared to $71.7 million of sale-leasebacks (capital leases) in 2005.

We believe that cash on hand, cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major acquisitions), scheduled debt payments, potential share repurchases, additional bonding requirements, requirements to secure additional obligations and anticipated dividend payments for at least the next few years. Nevertheless, our ability to satisfy debt service obligations, to fund planned capital expenditures, to repurchase shares or pay dividends will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, debt covenants and financial, business and other factors, some of which are beyond our control. We frequently evaluate potential acquisitions. In the past, we have funded acquisitions primarily with cash generated from operations, but we may consider a variety of other sources, depending on the size of any transaction, including debt or equity financing. Additional capital resources may not be available to us on terms that we find acceptable, or at all.

Share Repurchases

On November 14, 2005, the Board of Directors authorized a stock repurchase program, authorizing us to repurchase shares of Common Stock. We may repurchase Common Stock from time to time, as determined by our authorized officers, up to an aggregate amount not to exceed $500 million (excluding commissions) with free cash flow as existing financing covenants may permit. Existing covenants currently allow for up to approximately $18.5 million of share repurchases. The stock repurchases may be conducted on the open market, through privately negotiated transactions, through derivative transactions or thorough purchases made in accordance with Rule 10b5-1 of the Exchange Act, in compliance with the SEC's regulations and other legal requirements. The Repurchase Program does not require us to acquire any specific number of shares and may be terminated at any time. On April 24, 2006, the Board of Directors amended the program to allow up to $50 million of the $500 million of the share repurchases to commence using cash currently on hand. Share repurchases of $50 million using cash currently on hand were completed on June 8, 2006, with the purchase of 1.3 million shares at an average price of $38.47. No additional share repurchases have been made since that time. All shares repurchased under the program have been recorded as Treasury stock.

Contractual Obligations

We have various contractual obligations that are recorded as liabilities within the Consolidated Financial Statements in this Annual Report on Form 10-K. Other obligations, such as certain purchase commitments, operating lease agreements, and other executory contracts are not recognized as liabilities within the Consolidated Financial Statements but are required to be disclosed. The following table is a summary of our significant obligations as of December 31, 2006 and the future periods in which such obligations are expected to be settled in cash. The table does not include current liabilities accrued within the Consolidated Financial Statements, such as Accounts payable and Payroll and employee benefits.

	Payments Due by Period				
In thousands	**Total**	**Within 1 Year**	**2-3 Years**	**4-5 Years**	**Beyond 5 Years**
Long-term debt [1]	$ 1,564,289	$ 74,695	$ 149,391	$ 462,197	$ 878,006
Capital lease obligations [2]	12,657	3,095	4,512	5,050	-
Operating lease obligations [3]	149,168	26,308	65,416	43,327	14,117
Coal lease obligations [4]	185,245	16,989	32,876	25,645	109,735
Other purchase obligations [5]	214,382	140,273	48,888	12,945	12,276
Total Obligations	$ 2,125,741	$ 261,360	$ 301,083	$ 549,164	$ 1,014,134

(1) Long-term debt obligations reflect the future interest and principal payments of our fixed rate senior unsecured notes outstanding as of December 31, 2006. See Note 6 to the Notes to Consolidated Financial Statements for additional information.

(2) Capital lease obligations include the amount of imputed interest over the terms of the leases. See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(3) See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(4) Coal lease obligations include minimum royalties paid on leased coal rights. Certain coal leases do not have set expiration dates but extend until completion of mining of all merchantable and mineable coal reserves. For purposes of this table, we have generally assumed that minimum royalties on such leases will be paid for a period of 20 years.

(5) Other purchase obligations primarily include capital expenditure commitments for surface mining and other equipment as well as purchases of materials and supplies. We have purchase agreements with vendors for most types of operating expenses. However, our open purchase orders (which are not recognized as a liability until the purchased items are received) under these purchase agreements, combined with any other open purchase orders, are not material and are excluded from this table. Other purchase obligations also include contractual commitments under transportation contracts. Since the actual tons to be shipped under these contracts are not set and will vary, the amount included in the table reflects the minimum payment obligations required by the contracts.

Additionally, we have liabilities relating to pension and other postretirement benefits, work related injuries and illnesses, and mine reclamation and closure. As of December 31, 2006, payments related to these items are estimated to be:

Payments Due by Years (In Thousands)		
Within 1 Year	**2 - 3 Years**	**4 - 5 Years**
$63,103	$100,027	$109,465

Our determination of these noncurrent liabilities is calculated annually and is based on several assumptions, including then prevailing conditions, which may change from year to year. In any year, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Moreover, in particular for periods after 2006, the estimates may change from the amounts included in the table, and may change significantly, if assumptions change to reflect changing conditions. These assumptions are discussed in the Notes to Consolidated Financial Statements and in Critical Accounting Estimates and Assumptions of this Management's Discussion and Analysis of Financial Condition and Results of Operations section.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, 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 the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

We use surety bonds to secure reclamation, workers' compensation, wage payments, and other miscellaneous obligations. As of December 31, 2006, we had $337.5 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $307.4 million, workers' compensation bonds of $10.0 million, wage payment and collection bonds of $8.7 million, and other miscellaneous obligation bonds of $11.4 million.

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral. As of December 31, 2006, we had secured $42.2 million of surety obligations with letters of credit.

From time to time we use bank letters of credit to secure obligations for worker's compensation programs, various insurance contracts and other obligations. The Office of Workers' Claims for the Commonwealth of Kentucky has applied a new actuarial methodology for deriving surety obligations for existing claims, which has resulted in an assessment of an additional $37.1 million of surety. We have protested the assessment and, pending final resolution of the protest, the requirement for additional surety has been stayed. Any additional surety that is ultimately required will likely be satisfied with a bank letter of credit.

At December 31, 2006, we had $164.2 million of letters of credit outstanding (including the $42.2 million noted above that secure surety obligations), of which $100.0 million was collateralized by $105.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and $64.2 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2006.

Certain Trends and Uncertainties

Our inability to satisfy contractual obligations may adversely affect profitability.

From time to time, we have disputes with customers over the provisions of sales agreements relating to, among other things, coal pricing, quality, quantity, delays and force majeure declarations. Our inability to satisfy contractual obligations could result in the purchase of coal from third party sources to satisfy those obligations, the negotiation of settlements with customers, which may include price reductions, the reduction of commitments or the extension of the time for delivery, and customers terminating contracts, declining to do future business with us, or initiating claims against us. We may not be able to resolve all of these disputes in a satisfactory manner, which could result in the payment of substantial damages or otherwise harm our relationships with our customers.

We are subject to being adversely affected by the potential inability to renew or obtain surety bonds.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation, and to satisfy other miscellaneous obligations. These bonds are typically renewable annually. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral upon those renewals. We are also subject to increased in the amount of surety bonds required by federal and state laws as these laws change or the interpretation of these laws changes. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal law would have a material impact on us. That failure could result from a variety of factors including the following: (i) lack of availability, higher expense or unfavorable market terms of new bonds; (ii) restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our senior notes or revolving credit facilities; (iii) our inability to meet certain financial tests with respect to a portion of the post-mining reclamation bonds; and (iv) the exercise by third-party surety bond issuers of their right to refuse to renew or issue new bonds.

High oil prices could lead to a phase-out of IRC Section 45K tax credits (formerly Section 29), which would reduce our earnings from our operating and financial arrangements with a synfuel facility we previously owned and currently manage.

Owners of facilities that produce synthetic fuels can qualify for tax credits under the provisions of IRC Section 45K (formerly Section 29) ("Section 45K"). In 2001 and 2002, we sold most of our interest in a synfuel facility and subsequently entered into an agreement to manage the facility. As part of the compensation for the sale, we received a contingent promissory note that is paid on a cents per Section 45K credit dollar earned based on synfuel tonnage shipped through 2007.

The payments to be received under the contingent promissory note may be reduced or eliminated if the price of oil remains above a certain threshold price set by the IRS (the "threshold price"). Once the threshold price is reached, the Section 45K credits will be phased out ratably over a $13.50 per barrel range above the threshold price. The threshold price for 2005 was set by the IRS in April 2006 and at a level where there was no phase-out of 2005 Section 45K tax credits. The threshold price for 2006 is expected to be set by the IRS in April 2007. For fiscal year 2006, the average price of West Texas Intermediate crude oil was approximately $66.09 per barrel. At this price level a portion of the Section 45K credits for 2006 will likely be phased out, which reduced the amount of income we accrued in 2006 from payments to be received under the contingent promissory note. If the price of oil rises too high in 2007, the majority owner of the synfuel facility may decide to close the facility, which would eliminate all of our future earnings from our operating and financial arrangements with the synfuel facility.

Shortages of skilled labor in the Central Appalachian coal industry may pose a risk in achieving high levels of productivity at competitive costs.

Coal mining continues to be a labor-intensive industry. In recent years, we have experienced a shortage of experienced mine workers when the demand and prices for all specifications of coal we mine increased appreciably. The hiring of these less experienced workers has negatively impacted our productivity and cash costs. A continued lack of skilled miners could continue to have an adverse impact on our labor productivity and cost and our ability to meet current production requirements to fulfill existing sales commitments or to expand production to meet the increased demand for coal.

Fluctuations in transportation costs could affect the demand for coal.

Transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer's purchasing decision. Increases in transportation costs could make coal a less competitive source of energy. Such increases could have a material impact on our ability to compete with other energy sources and on our cash flows, results of operations or financial condition. Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country or the world, including coal imported into the U.S. (several U.S. ports have recently announced plans to increase their capacity to import coal). For instance, coal mines in the western U.S. could become an increasingly attractive source of coal to consumers in the eastern part of the country if the costs of transporting coal from the west were significantly reduced and rail capacity was increased.

Inflationary pressures on supplies and labor may adversely affect our profit margins.

Generally, inflation in the U.S. has been relatively low in recent years. However, over the course of the last two years, we have been significantly impacted by price inflation in many of the components of our Cost of produced coal revenue, such as fuel, steel, copper and labor. For instance, the prices of diesel fuel and copper increased approximately 20% and 37%, respectively, over the two-year period ending December 31, 2006. If the prices for which we sell our coal do not increase in step with rising costs, our profit margins will be reduced.

Critical Accounting Estimates and Assumptions

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts. These estimates and assumptions are based on information available as of the date of the financial statements. Significant changes to the estimates and assumptions used in determining certain liabilities described below could introduce substantial volatility to our costs. The following critical accounting estimates and assumptions were used in the preparation of the financial statements:

Defined Benefit Pension

The estimated cost and benefits of non-contributory defined benefit pension plans are determined by independent actuaries, who, with management's review and approval, use various actuarial assumptions, including discount rate, future rate of increase in compensation levels and expected long-term rate of return on pension plan assets. The discount rate is an estimate of the current interest rate at which the applicable liabilities could be effectively settled as of the measurement date. In estimating the discount rate, forecasted cash flows were discounted using each year's associated spot interest rate on high quality fixed income investments. At December 31, 2006 and 2005, the discount rate used to determine defined benefit pension liability was 5.90% and 5.75%, respectively. The rate of increase in compensation levels is determined based upon our long-term plans for such increases. The rate of increase in compensation levels used was 4.0% for the years ended December 31, 2006 and 2005. The expected long-term rate of return on pension plan assets is based on long-term historical return information and future estimates of long-term investment returns for the target asset allocation of investments that comprise plan assets. The expected long-term rate of return on plan assets used to determine expense in each period was 8.0%, 8.0%, and 8.5% for the years ended December 31, 2006, 2005 and 2004, respectively. A decrease in the expected rate of return assumption increases the defined benefit pension expense. See Note 5 to the Notes to Consolidated Financial Statements for further discussion on our pension plans.

Coal Workers' Pneumoconiosis

We are responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and various states' statutes, for the payment of medical and disability benefits to eligible recipients resulting from occurrences of coal workers' pneumoconiosis disease (black lung). An annual evaluation is prepared by independent actuaries, who, after review and approval by management, use various assumptions regarding disability incidence, medical costs trend, cost of living trend, mortality, death benefits, dependents and interest rates. We record expense related to this obligation using the service cost method. At December 31, 2006 and December 31, 2005, the discount rate used to determine the black lung liability was 5.90% and 5.75%, respectively. Included in Note 11 to the Notes to Consolidated Financial Statements is a medical cost trend and cost of living trend sensitivity analysis.

Workers' Compensation

Our operations have workers' compensation coverage through a combination of either self-insurance, participation in a state run program, or commercial insurance. We accrue for the self-insured liability by recognizing cost when it is probable that the liability has been incurred and the cost can be reasonably estimated. To assist in the determination of this estimated liability we utilize the services of third party administrators who derive claim reserves from historical experience. These third parties provide information to independent actuaries, who after review and consultation with management with regards to actuarial assumptions, including discount rate, prepare an evaluation of the self-insured liabilities. At December 31, 2006 and December 31, 2005, the discount rate used to determine the self-insured workers' compensation liability obligation was 5.00%. A decrease in the assumed discount rate increases the workers' compensation self-insured liability and related expense. Actual experience in settling these liabilities could differ from these estimates, which could increase our costs. See Note 11 to the Notes to Consolidated Financial Statements for further discussion on workers' compensation.

Other Postretirement Benefits

Our sponsored health care plans provide retiree health benefits to eligible union and non-union retirees who have met certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits, and retiree contributions. These plans are not funded. We pay costs as incurred by participants. The estimated cost and benefits of the retiree health care plans are determined by independent actuaries, who, after review and approval by Massey management, use various actuarial assumptions, including discount rate, expected trend in health care costs and per capita costs. At December 31, 2006 and December 31, 2005, the discount rate used to determine the other postretirement benefit liability was 5.90% and 5.75%, respectively. At December 31, 2006, our assumptions of the company health care plans' cost trend were projected at an annual rate of 8.2% ranging down to 5.0% by 2011 (9.0% ranging down to 5.0% by 2011 at December 31, 2005), and remaining level thereafter. Included in Note 10 to the Notes to Consolidated Financial Statements is a sensitivity analysis on the health care trend rate assumption.

Reclamation and Mine Closure Obligations

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Total reclamation and mine-closing liabilities are based upon permit requirements and engineering estimates related to these requirements. We account for our reclamation liabilities under SFAS 143. SFAS 143 requires that asset retirement obligations be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we considered the estimated current cost of reclamation and applied inflation rates and a third party profit, as necessary. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

Contingencies

We are parties to a number of other legal proceedings, incident to our normal business activities. These matters include contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition.

See Item 3. Legal Proceedings and Note 17 to the Notes to Consolidated Financial Statements for further discussion on our contingencies.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

We have a reserve for taxes that may become payable as a result of audits in future periods with respect to previously filed tax returns included in Other noncurrent liabilities (separate disclosure has not been made because the amount is not considered material). It is our policy to establish reserves for taxes that may become payable in future years as a result of an examination by tax authorities. We establish the reserves based upon management's assessment of exposure associated with permanent tax differences (i.e., tax depletion expense, etc.), tax credits and interest expense applied to temporary difference adjustments. The tax reserves are analyzed periodically and adjustments are made as events occur to warrant adjustment to the reserve. We are currently under audit from the IRS for the fiscal year ended October 31, 2001 and calendar years ended December 31, 2003 and 2004. Management believes that we have adequately provided for any income taxes and interest that may ultimately be paid with respect to all open tax years.

Coal Reserve Values

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves. Many of these uncertainties are beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our internal engineers, geologists and financial associates. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (i) geological conditions; (ii) historical production from similar areas with similar conditions; (iii) the assumed effects of regulations and taxes by governmental agencies; (iv) assumptions governing future prices; and (v) future operating costs.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties, and 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 will likely vary from estimates, and these variances may be material.

Stock Options

Prior to January 1, 2006, we accounted for stock-based compensation under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," as amended ("APB No. 25"). Generally no stock-based employee compensation cost for stock options was reflected in net income as all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of the grant.

On January 1, 2006, we adopted the provisions of Statement of Financial Accounting Standards No. 123R, "Share-Based Payments" ("SFAS 123R") using the modified prospective transition method. SFAS 123R eliminates the option of using the intrinsic value method of accounting previously available under APB No. 25, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We recorded stock option expense of $6.1 million, pre-tax, in Selling, general and administrative in 2006, as a result of the adoption of SFAS 123R. We anticipate the future expense of SFAS 123R to approximate current year expense. The Black-Scholes option pricing model is used to determine fair value of stock options at the grant date. Various inputs are utilized in the Black-Scholes pricing model, such as:

- Stock price on measurement date,
- Exercise price defined in the award,
- Expected dividend yield based on historical trend of dividend payouts,
- Risk-free interest rate based on a zero-coupon treasury bond rate,
- Expected term based on historical grant and exercise behavior, and
- Expected volatility based on historic and implied stock price volatility of our stock and public peer group stock.

These factors can significantly impact the value of stock option expense recognized over the requisite service period of option holders. As of December 31, 2006, $15 million of total unrecognized compensation cost related to unvested awards is expected to be recognized over a weighted-average period of 2.4 years. Refer to Note 12 in the Notes to Consolidated Financial Statements for more information.

Recent Accounting Pronouncements

Refer to Note 1 in the Notes to Consolidated Financial Statements for information concerning the effect of recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Discussions about Market Risk

Our net interest expense is sensitive to changes in the general level of short-term interest rates. At December 31, 2006, the outstanding $1,104.9 million of our debt was under fixed-rate instruments. Upon the termination of our $240 million interest rate swap agreement in December 2005, our interest expense is no longer sensitive to changes in the general level of short-term interest rates. However, if it should become necessary to borrow under our asset-based revolving credit facility, those borrowings would be made at a variable rate. Interest income is sensitive to changes in short-term interest rates. Assuming that Cash and cash equivalents was fixed at the December 31, 2006 level of $239.2 million, a hypothetical 100 basis point decrease in money market interest rates would result in a decrease of approximately $2.4 million in Interest income.

We manage market price risk for coal through the use of long-term coal supply agreements, which are contracts with a term of one year or more in duration, rather than through the use of derivative instruments. We estimate that the percentage of sales pursuant to these long-term contracts was 94% for our fiscal year ended December 31, 2006. We anticipate that in 2007, the percentage of our sales pursuant to long-term contracts will be comparable with the percentage of our sales for 2006. The prices for coal shipped under long-term contracts may be below the current market price for similar types of 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 stronger coal prices if and when they arise. In addition, because long-term contracts typically allow the customer to elect volume flexibility, 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 under such contracts, or our exposure to market-based pricing may be increased should customers elect to purchase fewer tons.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Massey Energy Company

We have audited the accompanying consolidated balance sheets of Massey Energy Company as of December 31, 2006 and 2005, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in 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 Massey Energy Company at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, 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 to the consolidated financial statements, in 2006 the Company changed its method of accounting for post-production stripping costs to comply with the accounting provisions of Emerging Issues Task Force No. 04-6, *Accounting for Stripping Costs Incurred During Production in the Mining Industry*. As discussed in Notes 5, 10 and 11 to the consolidated financial statements, in 2006 the Company changed its method of accounting for defined benefit pension and other post-retirement plans to comply with the accounting provisions of Financial Accounting Standards Board Statement No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statement Nos. 87, 77, 106, and 132(R)*. As discussed in Note 12 to the consolidated financial statements, in 2006 the Company changed its method of accounting for stock-based compensation to comply with the accounting provisions of Financial Accounting Standards Board Statement No. 123(R), *Share- Based Payment*. As discussed in Note 4 to the consolidated financial statements, in 2005 the Company changed it method of accounting for exchanges of nonmonetary assets to comply with the accounting provisions of Financial Accounting Standards Board Statement No. 153, *Exchanges of Nonmonetary Assets – an Amendment of APB opinion No. 29, Accounting for Nonmonetary Transactions*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Massey Energy Company's internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Richmond, Virginia
February 28, 2007

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands, Except Per Share Amounts)

	Year Ended December 31, 2006	December 31, 2005	December 31, 2004
Revenues			
Produced coal revenue	$ 1,902,259	$ 1,777,724	$ 1,456,684
Freight and handling revenue	156,531	150,898	148,795
Purchased coal revenue	70,636	132,320	104,955
Other revenue	90,428	143,316	56,210
Total revenues	2,219,854	2,204,258	1,766,644
Costs and expenses			
Cost of produced coal revenue	1,599,092	1,438,494	1,175,900
Freight and handling costs	156,531	150,898	148,795
Cost of purchased coal revenue	62,613	112,600	104,109
Depreciation, depletion and amortization, applicable to:			
Cost of produced coal revenue	227,279	230,545	220,135
Selling, general and administrative	3,259	4,020	4,482
Selling, general and administrative	53,834	68,254	57,525
Other expense	6,240	8,018	9,509
Loss on capital restructuring	-	212,378	-
Total costs and expenses	2,108,848	2,225,207	1,720,455
Income (Loss) before interest and taxes	111,006	(20,949)	46,189
Interest income	20,094	12,603	8,828
Interest expense	(86,076)	(67,064)	(60,660)
Income (Loss) before taxes	45,024	(75,410)	(5,643)
Income tax (expense) benefit	(3,408)	(26,228)	19,495
Income (Loss) before cumulative effect of accounting change	41,616	(101,638)	13,852
Cumulative effect of accounting change, net of tax	(639)	-	-
Net income (loss)	$ 40,977	$ (101,638)	$ 13,852
Income (Loss) per share - Basic			
Income (Loss) before cumulative effect of accounting change	$ 0.51	$ (1.33)	$ 0.18
Cumulative effect of accounting change	(0.01)	-	-
Net income (loss)	$ 0.50	$ (1.33)	$ 0.18
Income (Loss) per share - Diluted			
Income (Loss) before cumulative effect of accounting change	$ 0.51	$ (1.33)	$ 0.18
Cumulative effect of accounting change	(0.01)	-	-
Net income (loss)	$ 0.50	$ (1.33)	$ 0.18
Shares used to calculate income per share			
Basic	80,847	76,390	75,262
Diluted	81,386	76,390	76,450

See Notes to Consolidated Financial Statements

MASSEY ENERGY COMPANY
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 239,245	$ 319,418
Trade and other accounts receivable, less allowance of $576 and $2,063, respectively	197,105	152,564
Inventories	191,056	345,654
Deferred income taxes	-	5,182
Income taxes receivable	-	18,054
Other current assets	172,322	203,685
Total current assets	799,728	1,044,557
Net Property, Plant and Equipment	1,776,781	1,715,936
Other Noncurrent Assets		
Pension assets	34,974	78,702
Other noncurrent assets	129,213	147,327
Total other noncurrent assets	164,187	226,029
Total assets	$ 2,740,696	$ 2,986,522
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable, principally trade and bank overdrafts	$ 117,157	$ 162,789
Short-term debt	2,583	10,680
Payroll and employee benefits	40,380	40,914
Income taxes payable	19,412	-
Other current liabilities	175,005	159,347
Total current liabilities	354,537	373,730
Noncurrent Liabilities		
Long-term debt	1,102,324	1,102,582
Deferred income taxes	116,690	218,801
Other noncurrent liabilities	469,854	450,425
Total noncurrent liabilities	1,688,868	1,771,808
Total liabilities	2,043,405	2,145,538
Shareholders' Equity		
Capital stock		
Preferred – authorized 20,000,000 shares without par value; none issued	-	-
Common – authorized 150,000,000 shares of $0.625 par value; issued 82,365,259 and 81,939,989 shares, respectively	51,458	51,213
Treasury stock, 1,299,000 shares at cost	(49,995)	-
Additional capital	220,650	215,749
Unamortized executive stock plan expense	-	(7,130)
Retained earnings	515,894	581,621
Accumulated other comprehensive loss	(40,716)	(469)
Total shareholders' equity	697,291	840,984
Total liabilities and shareholders' equity	$ 2,740,696	$ 2,986,522

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Cash Flows from Operating Activities			
Net income (loss)	$ 40,977	$ (101,638)	$ 13,852
Adjustments to reconcile Net income (loss) to Cash provided by operating activities:			
Cumulative effect of accounting change	639	-	-
Depreciation, depletion and amortization	230,538	234,565	224,617
Share-based compensation expense	7,350	-	-
Deferred income taxes	(17,381)	23,259	1,181
Gain on disposal of assets	(46,557)	(63,879)	(22,789)
Gain on reserve exchange	-	(38,198)	-
Loss on repurchase of senior notes	-	669	1,279
Loss on debt restructuring	-	212,378	-
Writeoff of deferred financing costs	-	6,648	-
Accretion of asset retirement obligations	10,166	10,156	8,743
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(43,456)	13,559	(19,465)
Increase in inventories	(8,070)	(85,869)	(53,169)
Decrease (increase) in other current assets	24,573	(4,695)	26,582
Decrease (increase) in pension and other assets	1,165	(6,830)	(17,714)
(Decrease) increase in accounts payable and bank overdrafts	(45,632)	26,917	25,551
Increase (decrease) in accrued income taxes	42,638	15,320	(20,635)
Increase in other accrued liabilities	17,046	19,502	35,271
Increase in other noncurrent liabilities	4,712	12,140	29,446
Asset retirement obligation payments	(4,205)	(3,858)	(6,090)
Cash provided by operating activities	214,503	270,146	226,660
Cash Flows from Investing Activities			
Capital expenditures	(298,132)	(346,578)	(347,152)
Proceeds from sale of assets	51,467	73,542	57,731
Cash utilized by investing activities	(246,665)	(273,036)	(289,421)
Cash Flows from Financing Activities			
Repurchase of senior notes	-	(19,890)	(70,799)
Stock repurchase	(49,995)	-	-
Repayments of capital lease obligations	(10,214)	(19,370)	(17,770)
Proceeds from issuance of 6.875% senior notes	-	742,847	-
Proceeds from issuance of convertible senior notes	-	-	170,275
Debt restructuring	-	(562,608)	-
Early termination of fair value hedge	-	(7,922)	-
Proceeds from sale-leaseback transactions	21,819	71,697	15,000
Cash dividends paid	(12,814)	(12,208)	(12,024)
Proceeds from stock options exercised	2,142	7,231	11,857
Income tax benefit from stock option exercises	1,051	-	-
Cash (utilized) provided by financing activities	(48,011)	199,777	96,539
(Decrease) increase in cash and cash equivalents	(80,173)	196,887	33,778
Cash and cash equivalents at beginning of period	319,418	122,531	88,753
Cash and cash equivalents at end of period	$ 239,245	$ 319,418	$ 122,531
Supplemental Cash Flow Information			
Cash paid during the period for income taxes	$ 157	$ 9,205	$ 572

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(In Thousands, Except Per Share Amounts)

	Common Stock		Additional	Unamortized Executive Stock Plan	Retained	Accumulated Other Comprehensive	Treasury	Total Shareholders'
	Shares	Amount	Capital	Expense	Earnings	Loss	Stock	Equity
Balance at December 31, 2003	75,508	$ 47,193	$ 24,270	$ (6,219)	$ 693,712	$ -	$ -	$ 758,956
Net income					13,852			13,852
Other comprehensive loss, net of deferred tax of $81:								
Minimum pension liability adjustment						(151)		(151)
Comprehensive income								13,701
Dividends declared ($0.16 per share)					(12,072)			(12,072)
Exercise of stock options	890	557	11,300					11,857
Stock option tax benefit			2,046					2,046
Amortization of stock plan expense				2,385				2,385
Issuance of restricted stock, net	33	19	2,309	(2,328)				-
Balance at December 31, 2004	76,431	$ 47,769	$ 39,925	$ (6,162)	$ 695,492	$ (151)	$ -	$ 776,873
Net loss					(101,638)			(101,638)
Other comprehensive loss, net of deferred tax of $171:								
Minimum pension liability adjustment						(318)		(318)
Comprehensive loss								(101,956)
Dividends declared ($0.16 per share)					(12,233)			(12,233)
Exercise of stock options	498	312	6,919					7,231
Stock option tax benefit			2,563					2,563
Amortization of stock plan expense				3,153				3,153
Issuance of restricted stock, net	90	56	4,065	(4,121)				-
Issuance of stock for debt conversion	4,921	3,076	162,277					165,353
Balance at December 31, 2005	81,940	$ 51,213	$ 215,749	$ (7,130)	$ 581,621	$ (469)	$ -	$ 840,984
Net income					40,977			40,977
Other comprehensive income, net of deferred tax of $(21):								
Minimum pension liability adjustment						109		109
Comprehensive income								41,086
Adoption of accounting standards:								
Share-based payments			(7,130)	7,130				-
Post-production stripping costs, net of deferred tax of $59,970					(93,798)			(93,798)
Pension and postretirement plans,								-
net of deferred tax of $25,801						(40,356)		(40,356)
Dividends declared ($0.16 per share)					(12,906)			(12,906)
Stock option expense			6,112					6,112
Exercise of stock options	185	115	2,027					2,142
Stock option tax benefit			1,051					1,051
Restricted stock	239	129	2,822					2,951
Share repurchase	(1,299)						(49,995)	(49,995)
Issuance of stock for debt conversion	1	1	19					20
Balance at December 31, 2006	81,066	$ 51,458	$ 220,650	$ -	$ 515,894	$ (40,716)	$ (49,995)	$ 697,291

See Notes to Consolidated Financial Statements.

1. Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Massey Energy Company ("we", "our", or "us"), its wholly owned and sole, direct operating subsidiary A.T. Massey Coal Company, Inc. ("A.T. Massey") and A.T. Massey's wholly owned direct and indirect subsidiaries. Significant inter-company transactions and accounts are eliminated in consolidation. We have no independent assets or operations. We do not have a controlling interest in any separate independent operations. Investments in business entities in which we do not have control, but have the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method.

A.T. Massey fully and unconditionally guarantees our obligations under the 6.625% senior notes due 2010 ("6.625% Notes"), the 6.875% senior notes due 2013 ("6.875% Notes"), the 4.75% convertible senior notes due 2023 ("4.75% Notes") and the 2.25% convertible senior notes due 2024 ("2.25% Notes"). In addition, the 6.625% Notes, the 6.875% Notes and the 2.25% Notes are fully and unconditionally, jointly and severally guaranteed by A.T. Massey and substantially all of our indirect operating subsidiaries, each such subsidiary being indirectly 100% owned by us. The subsidiaries not providing a guarantee of the 6.625% Notes, the 6.875% Notes and the 2.25% Notes are minor (as defined under Securities and Exchange Commission ("SEC") Rule 3-10(h)(6) of Regulation S-X). See Note 6 for a more complete discussion of debt.

Use of Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States ("U.S.") requires management to make estimates and assumptions that affect reported amounts. These estimates are based on information available as of the date of the financial statements. Therefore, actual results could differ from those estimates. The most significant estimates used in the preparation of the consolidated financial statements are related to defined benefit pension plans, coal workers' pneumoconiosis ("black lung"), workers' compensation, other postretirement benefits, reclamation and mine closure obligations, contingencies, income taxes and coal reserve values.

Revenue Recognition

Produced coal revenue is realized and earned when risk of loss passes to the customer. Coal sales are made to our customers under the terms of coal supply agreements, most of which are long-term (one year or greater). Under the typical terms of these coal supply agreements, title and risk of loss transfer to the customer at the mine, dock, or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s) that serves each of our mines. We incur certain "add-on" taxes and fees on coal sales. Coal sales reported in Produced coal revenues include these "add-on" taxes and fees charged by various federal and state governmental bodies.

Freight and handling revenue consists of shipping and handling costs invoiced to coal customers and paid to third-party carriers. These revenues are directly offset by Freight and handling costs.

Purchased coal revenue represents revenue recognized from the sale of coal purchased from third-party production sources. We take title to the purchased coal, which we then resell to our customers. Typically, title and risk of loss transfer to the customer at the mine, dock or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s).

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, rentals, gas well revenue, gains on the sale of non-strategic assets, earnings from the sale and operation of the synfuel plant, joint venture revenue and other miscellaneous revenue. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced. Certain agreements require minimum lease payments regardless of the extent to which minerals are produced from the leasehold. The terms of these agreements generally range from specified periods of five to 15 years, or can be for an unspecified period until all reserves are depleted. See Note 14 for a discussion of the synfuel plant.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents consist of highly liquid investments with maturities of 90 days or less at the date of purchase.

Trade Receivables

Trade accounts receivable are recorded at the invoiced amount and are non-interest bearing. We maintain a bad debt reserve based upon the expected collectibility of our accounts receivable. The reserve includes specific amounts for accounts that are likely to be uncollectible, as determined by such variables as customer creditworthiness, the age of the receivables, bankruptcies and disputed amounts. Account balances are charged off against the reserve after all means of collection have been exhausted and the potential for recovery is considered remote.

Inventories

Produced coal and supplies inventories generally are stated at the lower of average cost or net realizable value. Coal inventory costs include labor, supplies, equipment costs, operating overhead and other related costs. Purchased coal inventories are stated at the lower of cost, computed on the first-in, first-out method, or net realizable value.

Prior to 2006, we accounted for the costs of removing overburden and waste materials (stripping costs) incurred during the production phase of a mine as a component of surface mining inventory costs. As overburden was removed, the stripping costs were captured in inventory costs and attributed to the proven reserves benefited. On January 1, 2006, we adopted Emerging Issues Task Force ("EITF") Issue No. 04-6, "Accounting for Stripping Costs Incurred During Production in the Mining Industry" ("EITF 04-6"). This consensus limits accounting for production-related stripping costs as a component of inventory to those costs associated with extracted or saleable inventories. Therefore, stripping costs in 2006 are recorded as Cost of produced coal revenue while 2005 stripping costs are shown in Inventories as Advance stripping costs.

Income Taxes

We account for income taxes in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes" ("SFAS 109"), which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

Property, Plant and Equipment

Property, plant and equipment are carried at cost and stated net of accumulated depreciation. Expenditures that extend the useful lives of existing buildings and equipment are capitalized. Maintenance and repairs are expensed as incurred. Coal exploration costs are expensed as incurred. Development costs applicable to the opening of new coal mines and certain mine expansion projects are capitalized until production begins. When properties are retired or otherwise disposed, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is credited or charged to Other revenue.

Our coal reserves are controlled either through direct ownership or through leasing arrangements. Mining properties owned in fee represent owned coal properties carried at cost. Leased mineral rights represent leased coal properties carried at the cost of acquiring those leases. The leases are generally long-term in nature (original term five to fifty years or until the mineable and merchantable coal reserves are exhausted), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues.

Depreciation of buildings, plants and equipment is calculated on the straight-line method over their estimated useful lives or lease terms as follows:

	Years
Buildings and plants	15 to 30
Equipment	3 to 20
Capital leases	2 to 10

Ownership of assets under capital leases transfers to us at the end of the lease term. Depreciation of assets under capital leases is included within Depreciation, depletion and amortization.

Amortization of development costs is computed using the units-of-production method over the estimated proven and probable reserve tons.

Depletion of mining properties owned in fee and leased mineral rights is computed using the units-of-production method over the estimated proven and probable reserve tons. As of December 31, 2006, approximately $45.2 million of costs associated with mining properties owned in fee and leased mineral rights is not currently subject to depletion as mining has not begun or production has been temporarily idled on the associated coal reserves.

We capitalize 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 costs capitalized are amortized using the straight-line method over the estimated useful life not to exceed 7 years.

Impairment of Long-Lived Assets

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets and the estimated fair value are less than the assets' carrying value. The carrying value of the assets is then reduced to their estimated fair value, which is usually measured based on an estimate of future discounted cash flows. There were no material impairment losses recorded during the periods covered by the consolidated financial statements.

Advance Mining Royalties

Coal leases that require minimum annual or advance payments and are recoverable from future production are generally deferred and charged to expense as the coal is subsequently produced. At December 31, 2006 and 2005, advance mining royalties included in Other noncurrent assets totaled $35.1 million and $36 million, net of an allowance of $17.8 million and $16.3 million, respectively.

Reclamation

We account for reclamation liabilities in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 requires that asset retirement obligations ("ARO") be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows, in the period in which it is incurred. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates and a third party profit, as necessary. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. 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. Accretion expense is included in Cost of produced coal revenue. 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. Additionally, we perform a certain amount of required reclamation of disturbed acreage as an integral part of our normal mining process; these costs are expensed as incurred.

Pension Plans

We sponsor a noncontributory defined benefit pension plan covering substantially all administrative and non-union employees. Our policy is to annually fund the defined benefit pension plan at or above the minimum amount required by law. We also sponsor a nonqualified supplemental benefit pension plan for certain salaried employees, which is unfunded.

We account for our defined benefit pension plans in accordance with SFAS No. 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS 158"). SFAS 158 requires us to recognize the funded status of our benefit plans in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost. We adopted SFAS 158 as of December 31, 2006. See Note 5 for a more complete discussion of our pension plans.

Workers' Compensation and Black Lung Benefits

We are liable for workers' compensation benefits for traumatic injuries under state workers' compensation laws in which we have operations. Our operations have workers' compensation coverage through a combination of either a self-insurance program, as a participant in a state run program, or by an insurance policy. We record the liability on a discounted actuarial basis using various assumptions, including discount rate and future cost trends.

We are also responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and various states' statutes for the payment of medical and disability benefits to employees and their dependents resulting from occurrences of black lung. We provide for federal and state black lung claims principally through a self-insurance program. Provisions for estimated benefits are determined on an actuarial basis. See Note 11 for a more complete discussion of workers' compensation and black lung benefits.

Postretirement Benefits Other than Pensions

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union members. Postretirement benefits other than pensions are accounted for in accordance with SFAS 158, which requires us to recognize the funded status of our benefit plans in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost. We adopted SFAS 158 as of December 31, 2006.

Under the Coal Industry Retiree Health Benefits Act of 1992 (the "Coal Act"), coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the United Mine Workers of America ("UMWA") Benefit Funds. We treat our obligation under the Coal Act as participation in a multi-employer plan as permitted by EITF No. 92-13, "Accounting for Estimated Payments in Connection with the Coal Industry Retiree Health Benefit Act of 1992," and record the cost of our obligation as expense as payments are assessed. See Note 10 for a more complete discussion of postretirement benefits other than pensions.

Stock-based Compensation

Prior to 2006, we accounted for stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," ("APB No. 25") and related interpretations. On January 1, 2006, we adopted Financial Accounting Standards Board ("FASB") Statement No. 123(R), "Share-Based Payments" ("SFAS 123R") using the modified-prospective method. The modified-prospective method requires us to recognize compensation cost of equity instruments based on their grant-date fair value. Results from prior periods have not been restated. A cumulative effect of a change in accounting principle of $0.6 million loss (net of $0.4 million tax) was recognized to reflect a change to the fair value method for those liability awards previously accounted for using the intrinsic value method and to reflect the impact of estimated forfeitures. We use the Black-Scholes option-pricing model to determine the fair value of stock options as of the date of grant and certain liability awards with option characteristics (i.e., stock appreciation rights, or "SARs"). For periods after the adoption date, compensation cost for both equity and liability awards will be measured and recorded in accordance with the provisions of SFAS 123R. See Note 12 for a more complete discussion of stock-based compensation.

Earnings per Share

The number of shares used to calculate basic earnings (loss) per share is based on the weighted average number of our outstanding common shares during the respective periods. The number of shares used to calculate diluted earnings (loss) per share is based on the number of common shares used to calculate basic earnings (loss) per share plus the dilutive effect of stock options and other stock-based instruments held by our employees and directors during each period and debt securities currently convertible into our common stock, $0.625 par value ("Common Stock") during the period. In accordance with accounting principles generally accepted in the U.S., the effect of dilutive securities in the amount of 0.3 million, 13 million and 10.3 million for the years ended December 31, 2006, 2005 and 2004, respectively, was excluded from the calculation of the diluted earnings (loss) per common share as such inclusion would result in antidilution.

The computation for basic and diluted earnings (loss) per share is based on the following per share information:

	Year Ended		
	December 31, 2006	December 31, 2005	December 31, 2004
	(In Thousands, Except Per Share Amounts)		
Numerator:			
Income (Loss) before cumulative effect of accounting change	$ 41,616	$ (101,638)	$ 13,852
Cumulative effect of accounting change, net of tax	(639)	-	-
Net income (loss) - numerator for basic and diluted	$ 40,977	$ (101,638)	$ 13,852
Denominator:			
Weighted average shares - denominator for basic	80,847	76,390	75,262
Effect of stock options/restricted stock	539	-	1,188
Adjusted weighted average shares - denominator for diluted	81,386	76,390	76,450
Income (Loss) per share:			
Basic:			
Before cumulative effect of accounting change	$ 0.51	$ (1.33)	$ 0.18
Cumulative effect of accounting change	(0.01)	-	-
Net income (loss)	$ 0.50	$ (1.33)	$ 0.18
Diluted:			
Before cumulative effect of accounting change	$ 0.51	$ (1.33)	$ 0.18
Cumulative effect of accounting change	(0.01)	-	-
Net income (loss)	$ 0.50	$ (1.33)	$ 0.18

Accounting Pronouncements

Inventory Costs

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs: An Amendment of ARB 43, Chapter 4" ("SFAS 151"). SFAS 151 amends the guidance in Accounting Research Bulletin ("ARB") No. 43, Chapter 4, "Inventory Pricing," to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs, and wasted material (spoilage). Paragraph 5 of ARB 43, Chapter 4 previously stated that "under some circumstances, items such as idle facility expense, excess spoilage, double freight, and re-handling costs may be so abnormal as to require treatment as current period charges." SFAS 151 requires that those items be recognized as current-period charges regardless of whether they meet the criterion of "so abnormal." In addition, SFAS 151 requires that allocation of fixed production overhead to the costs of conversion be based on the normal capacity of the production facilities. The provisions of SFAS 151 are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We adopted SFAS 151 on January 1, 2006. The adoption of SFAS 151 did not have a material impact on our financial statements.

Share-based Payments

On December 16, 2004, the FASB issued SFAS 123R which requires all share-based payments to employees, including grants of employee stock options, be recognized in the income statement based on their grant date fair values for interim or annual periods beginning after June 15, 2005. Pro forma disclosure of stock option expense is no longer permitted. The cost will be recognized over the requisite service period that an employee must provide to earn the award (i.e., usually the vesting period). We adopted SFAS 123R on January 1, 2006 using the "modified prospective" method and accordingly, the financial statements for prior periods do not reflect any restated amounts. A cumulative effect of a change in accounting principle of $0.6 million loss (net of tax) was recognized to reflect a change to the fair value method for those liability awards previously accounted for using the intrinsic value method and to reflect the impact of estimated forfeitures. SFAS 123R also requires the benefits of tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under previous literature. This requirement reduces net operating cash flows and increases net financing cash flows in periods after adoption.

Post-production Stripping Costs

In May 2005, the EITF reached a consensus on EITF 04-6 regarding the accounting for post-production stripping costs. The consensus reached was that "stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced (extracted) during the period that the stripping costs are incurred." This consensus limits accounting for production-related stripping costs as a component of inventory to merely those costs associated with extracted or saleable inventories. Therefore, stripping costs associated with in-process (i.e., uncovered, but unextracted) production shall not be recognized in inventory under this consensus, but shall be recorded as Cost of produced coal revenue. This represents a significant change from our prior accounting for production-related stripping costs, as through 2005, we included production-related stripping costs as a component of surface mining inventory and allocated the costs incurred over the estimated total reserves of the mine. We adopted EITF 04-6 on January 1, 2006. See Note 2 for further information about the effects of adoption.

Accounting Changes and Error Corrections

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections" ("SFAS 154"). The standard is a replacement of APB Opinion No. 20 and SFAS No. 3, as a result of an effort by the FASB to improve the comparability of financial reporting by working with the International Accounting Standards Board toward development of a single set of quality accounting standards. This statement addresses accounting changes and error corrections, and requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable. When impracticable, SFAS 154 requires the provisions of this statement to be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets). This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, with early adoption permitted. We adopted SFAS 154 on January 1, 2006. The adoption of SFAS 154 did not have a material impact on our financial statements.

Defined Benefit Pension and Other Postretirement Plans

In September 2006, the FASB also issued SFAS 158 which requires us to recognize the funded status of our benefit plans in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost. We adopted SFAS 158 as of December 31, 2006. The table below details the incremental effect of applying SFAS 158 on individual line items of the Consolidated Balance Sheet. See Notes 5, 10 and 11 for further information on the effects of adoption related to each plan.

	December 31, 2006 (In Thousands)		
	Before Application of SFAS 158	Adjustments	After Application of SFAS 158
Pension assets	$ 88,126	$ (53,152)	$ 34,974
Current liabilities	(9,207)	-	(9,207)
Other noncurrent liabilities	(181,877)	(13,005)	(194,882)
Deferred income tax asset	231	25,801	26,032
Accumulated other comprehensive loss	360	40,356	40,716

Uncertainty in Income Taxes

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48") to create a single model to address accounting for uncertainty in tax positions. FIN 48 clarifies the accounting for income taxes by prescribing a minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. We will adopt FIN 48 as of January 1, 2007, as required. The cumulative effect of adopting FIN 48 will be recorded in retained earnings and other accounts as applicable. We are currently assessing the potential impact of the statement on our financial position and results of operations.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value in accounting principles generally accepted in the U.S., and expands disclosures about fair value measurement. It does not require any new fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are currently assessing the potential impact of the statement on our financial position and results of operations.

2. Inventories

Inventories consisted of the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
Saleable coal	$ 124,816	$ 118,677
Raw coal	13,210	20,339
Advance stripping costs	-	162,390
Subtotal coal inventory	138,026	301,406
Supplies inventory	53,030	44,248
Total inventory	$ 191,056	$ 345,654

Saleable coal represents coal ready for sale, including inventories designated for customer facilities under consignment arrangements of $61.0 million and $56.8 million at December 31, 2006 and 2005, respectively. Raw coal represents coal that generally requires further processing prior to shipment to the customer. At December 31, 2005, Advance stripping costs consisted of the costs incurred to remove overburden above an unmined coal seam as part of the surface mining process.

In March 2005, the EITF reached a consensus regarding the accounting for post-production stripping costs codified in EITF 04-6. EITF 04-6 states, "stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced (extracted) during the period that the stripping costs are incurred." This consensus limits accounting for production-related stripping costs as a component of inventory to merely those costs associated with extracted or saleable inventories. Therefore, stripping costs associated with in-process (i.e., uncovered, but unextracted) production shall not be recognized in inventory under this consensus, but shall be recorded as Cost of produced coal revenue. This represents a significant change from our prior accounting for production-related stripping costs that included production-related stripping costs as a component of surface mining inventory.

EITF 04-6 became effective for the first reporting period beginning after December 15, 2005. The transition provisions of EITF 04-6 allow for a cumulative effect adjustment approach where the cumulative effect adjustment is recorded directly to Retained earnings in the year of adoption. We adopted EITF 04-6 on January 1, 2006.

Adoption of the new rule resulted in a $162.7 million reduction in coal inventory, an $8.9 million increase in mine development, and a reduction of $93.8 million (net of $60 million in taxes) in Retained earnings on January 1, 2006. In accordance with the new rule, costs associated with removing overburden on surface mines are now charged to mine development until such time as coal is extracted from the ground (more than a de minimis amount). After such time, all costs are recorded as Cost of produced coal revenue.

3. Other Current Assets

Other current assets are comprised of the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
Longwall panel costs	$ 38,843	$ 65,648
Deposits	106,833	115,398
Other	26,646	22,639
Total other current assets	$ 172,322	$ 203,685

Deposits consist primarily of funds placed in restricted accounts with financial institutions to collateralize letters of credit that support workers' compensation requirements, insurance and other obligations. Deposits at December 31, 2006 and 2005 include $105 million of funds pledged as collateral to support outstanding letters of credit (see Note 6 for further discussion).

4. Property, Plant and Equipment

Property, plant and equipment is comprised of the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
Land, buildings and equipment	$ 2,005,029	$ 1,890,271
Mining properties owned in fee and leased mineral rights	690,687	683,826
Mine development	781,834	709,525
Total property, plant and equipment	3,477,550	3,283,622
Less accumulated depreciation, depletion and amortization	(1,700,769)	(1,567,686)
Net property, plant and equipment	$ 1,776,781	$ 1,715,936

Land, buildings and equipment includes gross assets under capital leases of $32.3 million and $48.9 million at December 31, 2006 and 2005, respectively.

During the third quarter of 2006, we sold our Falcon reserves, located in Boone County, West Virginia, to a privately held coal company for total consideration of $30.8 million in cash. The sale consisted of approximately 5.5 million tons of coal. The total gain recognized on the sale was $30.0 million (pre-tax), which is included within Other revenue for 2006.

During 2006 and 2005, we sold and leased-back certain mining equipment in several transactions for net proceeds of $21.8 million and $71.7 million, respectively. See Note 13 for further details.

During the third quarter of 2005, we exchanged coal reserves with a third party, recognizing a gain of $38.2 million (pre-tax) in accordance with SFAS 153. The fair value of the assets surrendered by both parties was determined by use of a future cashflows valuation model. The difference in the fair value of the assets surrendered and their book basis resulted in the gain recognized. The gain from this transaction is recorded in Other revenue. The acquired coal reserves were recorded in Property, plant and equipment at the fair value of the reserves surrendered.

During the first quarter of 2005, we sold our ownership interest in the property known as Big Elk Mining Company to a privately held coal company for total consideration of $52.5 million in cash and non-interest bearing notes, plus the assumption of reclamation liabilities associated with the property of approximately $10.1 million. The Big Elk operations included a preparation plant, rail loadout and approximately 12 million tons of coal reserves. Included in the sale were approximately 5 million tons of coal reserves in Mingo and McDowell Counties, West Virginia, held by two separate subsidiaries. The gain recognized on the sale was $45.9 million (pre-tax), which is included within Other revenue for 2005.

5. Pension Plans

Defined Benefit Pension Plans

We sponsor a qualified non-contributory defined benefit pension plan, which covers substantially all administrative and non-union employees. Based on a participant's entrance date to the plan, the participant may accrue benefits based on one of four benefit formulas. Two of the formulas provide pension benefits based on the employee's years of service and average annual compensation during the highest five consecutive years of service. The third formula credits certain eligible employees with flat dollar contributions based on years of service with Massey and years of service under the UMWA 1974 Pension Plan. The fourth formula provides benefits under a cash balance formula with contribution credits based on hours worked. There is a guaranteed rate of return on contributions of 4% for all contributions after January 1, 2004. Funding for the plan is generally at the minimum contribution level required by applicable regulations. We made voluntary contributions of $18.1 million and $17.4 million to the qualified plan during 2006 and 2005, respectively.

An independent trustee holds the plan assets for the qualified defined benefit pension plan. The plan's assets include cash and cash equivalents, corporate and government bonds, preferred and common stocks and an investment in a group annuity contract. There were no investments in Common Stock held by the plan at December 31, 2006 or 2005. We have an internal investment committee ("Investment Committee") that sets investment policy, selects and monitors investment managers and monitors asset allocation. Diversification of assets is employed to reduce risk. The target asset allocation is 65% for equity securities (including 50% domestic and 15% international) and 35% for cash and interest bearing securities. The investment policy is based on the assumption that the overall portfolio volatility will be similar to that of the target allocation. Given the volatility of the capital markets, strategic adjustments in various asset classes may be required to rebalance asset allocation back to its target policy. Investment fund managers are not permitted to invest in certain securities and transactions as outlined by the investment policy statements specific to each investment category without prior Investment Committee approval.

To develop the expected long-term rate of return on assets assumption, we considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio. This resulted in the selection of the 8.0% long-term rate of return on assets assumption for the year ended December 31, 2006.

The fair value of the major categories of qualified defined benefit pension plan assets includes the following:

	December 31, 2006		December 31, 2005	
	(Dollars In Thousands)			
Equity securities (domestic and international)	$ 186,695	65.4%	$ 163,668	66.3%
Debt securities	77,902	27.3%	69,365	28.1%
Other (includes cash, cash equivalents and a group annuity contract)	20,822	7.3%	13,959	5.6%
Total fair value of plan assets	$ 285,419	100.0%	$ 246,992	100.0%

In addition to the qualified defined benefit pension plan noted above, we sponsor a nonqualified supplemental benefit pension plan for certain salaried employees. Participants in this nonqualified supplemental benefit pension plan accrue benefits under the same formula as the qualified defined benefit pension plan, however, where the benefit is capped by Internal Revenue Service ("IRS") limitations, this nonqualified supplemental benefit pension plan compensates for benefits in excess of the IRS limit. This supplemental benefit pension plan is unfunded, with benefit payments paid by us.

The following table sets forth the change in benefit obligation, plan assets and funded status of both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan:

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 242,400	$ 226,677
Service cost	9,230	9,324
Interest cost	13,922	12,864
Actuarial loss	957	3,267
Benefits paid	(9,584)	(9,732)
Benefit obligation at the end of the period	$ 256,925	$ 242,400
Change in plan assets:		
Fair value at the beginning of the period	$ 246,992	$ 226,428
Actual return on assets	29,873	12,894
Company contributions	18,138	17,402
Benefits paid	(9,584)	(9,732)
Fair value of plan assets at end of period	$ 285,419	$ 246,992
Funded status	$ 28,494	$ 4,592
Unrecognized net actuarial loss	-	68,995
Unrecognized prior service cost	-	178
Accrued pension assets recognized (net)	$ 28,494	$ 73,765

In 2005, the provisions of SFAS No. 87, "Employers' Accounting for Pension" ("SFAS 87"), required the recognition of an additional minimum liability and related intangible asset for plans with an accumulated benefit obligation ("ABO") in excess of plan assets. No minimum pension liability was required at December 31, 2005 for the qualified defined benefit pension plan as the fair value of the plan assets exceeded the ABO. The nonqualified supplemental benefit pension plan is an unfunded plan and required an increase in minimum liability of $489,000 at December 31, 2005. This amount was included in Accumulated other comprehensive loss, net of $252,000 deferred tax.

As discussed in Note 1, we adopted SFAS 158 on December 31, 2006. As a result of adoption, we recognized the funded status of the qualified defined benefit pension plan and the nonqualified supplemental benefit pension plan in the Consolidated Balance Sheet. The table below details the incremental changes to the Consolidated Balance Sheet related to defined benefit pension plans due to the adoption of SFAS 158:

	December 31, 2006 (In Thousands)		
	Before Application of SFAS 158	Adjustments	After Application of SFAS 158
Pension assets	$ 88,126	$ (53,152)	$ 34,974
Other noncurrent liabilities	(6,281)	(199)	(6,480)
Deferred income tax asset	231	20,806	21,037
Accumulated other comprehensive loss	360	32,545	32,905

Included in Accumulated other comprehensive loss prior to any deferred tax effects as of December 31, 2006, is $53.8 million of net actuarial loss and $137,000 of prior service cost. We expect to recognize $40,000 of prior service cost and $3.1 million of net loss in 2007.

The assumptions used in determining pension benefit obligations for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2006	December 31, 2005
Discount rates	5.90%	5.75%
Rates of increase in compensation levels	4.00%	4.00%
Measurement date	12/31/2006	12/31/2005

Net periodic pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan includes the following components:

	Year Ended		
	December 31, 2006	December 31, 2005	December 31, 2004
		(In Thousands)	
Service cost	$ 9,230	$ 9,324	$ 8,032
Interest cost	13,922	12,864	12,121
Expected return on plan assets	(19,952)	(17,737)	(16,966)
Recognized loss	6,226	3,607	3,148
Amortization of prior service cost	39	40	39
Net periodic pension expense	$ 9,465	$ 8,098	$ 6,374

The assumptions used in determining pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2006	December 31, 2005	December 31, 2004
Discount rates	5.75%	5.75%	6.25%
Rates of increase in compensation levels	4.00%	4.00%	4.00%
Expected long-term rate of return on plan assets	8.00%	8.00%	8.50%
Measurement date	1/1/2006	1/1/2005	1/1/2004

We do not expect that any contributions will be required in 2007 for the qualified defined benefit pension plan. We expect to voluntarily contribute $0.1 million for benefit payments to participants in 2007 for the nonqualified supplemental benefit pension plan.

The following benefit payments from both the qualified defined benefit pension plan and the nonqualified supplemental benefit pension plan, which reflect expected future service, as appropriate, are expected to be paid from the plans:

	Expected Pension Benefit Payments
	(In Thousands)
2007	$ 10,636
2008	11,251
2009	12,014
2010	12,730
2011	13,485
Years 2012 to 2016	82,877

Multi-Employer Pension

Under labor contracts with the UMWA, certain operations make payments into two multi-employer defined benefit pension plan trusts established for the benefit of certain union employees. The contributions are based on tons of coal produced and hours worked. Such payments aggregated less than $100,000 in each of the years ended December 31, 2006, 2005 and 2004.

Defined Contribution Plan

We currently sponsor a defined contribution pension plan for certain union employees. The plan is non-contributory and our contributions are based on hours worked. Contributions to this plan were approximately $100,000 for each of the years ended December 31, 2006, 2005 and 2004.

Salary Deferral and Profit Sharing (401(K)) Plan

We also sponsor a salary deferral and profit sharing plan covering substantially all administrative and non-union employees. The maximum salary deferral rate is 75% (effective January 1, 2005) of eligible pay, subject to IRS limitations. We contribute a fixed match on employee contributions on up to 10% of eligible pay. Our contributions aggregated approximately $3.9 million, $3.7 million and $2.9 million for the years ended December 31, 2006, 2005 and 2004.

6. Debt

Our debt is comprised of the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 754,804	$ 754,277
6.625% senior notes due 2010	335,000	335,000
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	730	750
Capital lease obligations	11,232	21,443
Fair value hedge adjustment	(6,506)	(7,855)
Total debt	1,104,907	1,113,262
Amounts due within one year	(2,583)	(10,680)
Total long-term debt	$ 1,102,324	$ 1,102,582

The weighted average effective interest rate of the outstanding borrowings was 7.0% at December 31, 2006 and 2005. At December 31, 2006, our available liquidity was $350.0 million, including $239.2 million of cash and cash equivalents and $110.8 million availability on our asset-based revolving credit facility.

Refinancing Transactions

On November 22, 2005, we commenced a cash tender offer for any and all of the outstanding $220.1 million of 6.95% senior notes due 2007 (the "6.95% Notes"), a cash tender offer for any and all of the outstanding $132.0 million of 4.75% Notes and an exchange offer for any and all of our outstanding $175.0 million of 2.25% Notes.

On December 9, 2005, we commenced a private offering of the 6.875% Notes and announced our intention to use the proceeds of the offering to purchase the 6.95% Notes in connection with the 6.95% Notes tender offer, the redemption of any of the 6.95% Notes that were not tendered in the 6.95% Notes tender offer, the purchase of the 4.75% Notes in connection with the 4.75% Notes tender offer, the cash payment related to the exchange offer for the 2.25% Notes and for general corporate purposes.

On December 21, 2005, we settled with holders of $189.5 million of the $220.1 million outstanding of the 6.95% Notes, representing approximately 86.0% of the outstanding 6.95% Notes, who tendered their 6.95% Notes. On December 27, 2005, we redeemed the remaining $30.6 million of the 6.95% Notes.

On December 28, 2005, we accepted tender of 4.75% Notes from holders of $131.3 million, or 99.4%, of the outstanding 4.75% Notes.

On December 28, 2005, under the terms of the 2.25% Notes exchange offer, we exchanged shares of Common Stock and a cash payment for $165.4 million, or 94.5%, of the outstanding 2.25% Notes tendered by the holders.

We recognized charges totaling $219.0 million (pre-tax), including $6.6 million (pre-tax) for the write-off of unamortized financing fees, for the debt repurchase and exchange offer as of December 31, 2005.

6.875% Notes

On December 21, 2005, we completed a private placement sale under Rule 144A of the Securities Act of 1933, as amended, of $760 million of 6.875% senior notes due 2013 resulting in net proceeds of $742.8 million. We paid $12.4 million in financing fees, which were deferred and recorded in Other noncurrent assets. The 6.875% Notes were offered at a price of $992.43 per $1,000 note. The 6.875% Notes are unsecured obligations ranking equally with all other unsecured senior indebtedness of ours and are guaranteed by substantially all of our current and future subsidiaries. Interest on the 6.875% Notes is payable on December 15 and June 15 of each year. We may redeem the 6.875% Notes, in whole or in part, for cash at any time on or after December 15, 2009 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. At any time on or before December 15, 2008, we may redeem up to 35% of the principal amount of the 6.875% Notes with the proceeds of qualified equity offerings at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest. The 6.875% Notes are guaranteed by A.T. Massey and substantially all of our current and future operating subsidiaries (the "Guarantors"). The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.875% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

The 6.875% Notes contain a number of significant restrictions and covenants that limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries.

6.625% Notes

The 6.625% senior notes due 2010 are unsecured obligations of ours and rank equally with all other unsecured senior indebtedness. Interest is payable semiannually on May 15 and November 15 of each year. We may redeem the 6.625% Notes, in whole or in part, at any time on or after November 15, 2007 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. At any time on or before November 15, 2006, we may redeem up to 35% of the principal amount of the 6.625% Notes with the proceeds of qualified equity offerings at a redemption price of 106.625% of the principal amount, plus accrued and unpaid interest. The 6.625% Notes are guaranteed by the Guarantors. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.625% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

The 6.625% Notes contain a number of significant restrictions and covenants that limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries.

6.95% Notes

The 6.95% senior notes due 2007 were unsecured obligations of ours and ranked equally with all other unsecured senior indebtedness. During 2005 and 2004, we made several open-market purchases, retiring a total principal amount of $19.1 million and $43.8 million, respectively, of the 6.95% Notes at a cost of $19.8 million and $45.1 million, respectively. A loss of $0.7 million and $1.3 million related to the repurchases were recognized in 2005 and 2004, respectively, and are shown in the Consolidated Statements of Income in Other expense.

As discussed within this Note under Refinancing Transactions above, on December 21, 2005 and December 27, 2005, we accepted the tender of $189.5 million of the $220.1 million outstanding of the 6.95% Notes and redeemed the remaining $30.6 million of the 6.95% Notes, respectively.

2.25% Notes

The 2.25% convertible senior notes due 2024 are unsecured obligations of ours, rank equally with all other unsecured senior indebtedness and are guaranteed by the Guarantors. Interest is payable semiannually on April 1 and October 1 of each year. We registered the 2.25% Notes with the SEC for resale.

Holders of the 2.25% Notes may require us to purchase all or a portion of their notes for cash on April 1, 2011, 2014, and 2019, at a purchase price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest. In addition, if we experience certain specified types of fundamental changes on or before April 1, 2011, the holders may require us to purchase the notes for cash. We may redeem all or a portion of the 2.25% Notes for cash at any time on or after April 6, 2011, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest.

The 2.25% Notes are convertible during certain periods by holders into shares of Common Stock initially at a conversion rate of 29.7619 shares of Common Stock per $1,000 principal amount of 2.25% Notes (subject to adjustment upon certain events) under the following circumstances: (i) if the price of Common Stock issuable upon conversion reaches specified thresholds; (ii) if we redeem the 2.25% Notes; (iii) upon the occurrence of certain specified corporate transactions; or (iv) if the credit ratings assigned to the 2.25% Notes decline below certain specified levels. Regarding the thresholds in (i) above, holders may convert each of their notes into shares of Common Stock during any calendar quarter (and only during such calendar quarter) if the last reported sale price of Common Stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% of the conversion price per share of Common Stock. The conversion price is $33.60 per share. None of the 2.25% Notes are currently eligible for conversion. As of December 31, 2006, if all of the notes outstanding were eligible and were converted, we would have needed to issue 287,113 shares of Common Stock.

4.75% Notes

The 4.75% convertible senior notes due 2023 are unsecured obligations of ours, rank equally with all other unsecured senior indebtedness and are guaranteed by our wholly owned subsidiary, A.T. Massey, which together with our subsidiaries accounts for substantially all of our assets and all of our revenues. Interest is payable semiannually on May 15 and November 15 of each year. We registered the 4.75% Notes with the SEC for resale.

We may be required by the holders of the 4.75% Notes to purchase all or a portion of their notes on May 15, 2009, 2013, and 2018. For purchases on May 15, 2009, we must pay cash for all 4.75% Notes so purchased. For purchases on May 15, 2013 or 2018, we may, at our option, choose to pay the purchase price for such 4.75% Notes in cash, in shares of Common Stock or any combination thereof. We may redeem some or all of the 4.75% Notes at any time on or after May 20, 2009, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest.

The 4.75% Notes are convertible during certain periods by holders into shares of Common Stock initially at a conversion rate of 51.573 shares of Common Stock per $1,000 principal amount of 4.75% Notes (subject to adjustment upon certain events) under the following circumstances: (i) if the price of Common Stock issuable upon conversion reaches specified thresholds; (ii) if we redeem the 4.75% Notes; (iii) upon the occurrence of certain specified corporate transactions; or (iv) if the credit ratings assigned to the 4.75% Notes decline below specified levels. Regarding the thresholds in (i) above, holders may convert each of their notes into shares of Common Stock during any calendar quarter (and only during such calendar quarter) if the last reported sale price of Common Stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% of the conversion price per share of Common Stock. The conversion price is $19.39 per share.

In August 2006, $20,000 of principal amount of the 4.75% Notes was converted into 1,031 shares of Common Stock.

As of December 31, 2006, the price of Common Stock had reached the specified threshold for conversion. Consequently, the 4.75% Notes are convertible until March 31, 2007, the last day of our first quarter. The 4.75% Notes may be convertible beyond this date if the specified threshold for conversion is met in subsequent quarters. As of December 31, 2006, if all of the notes outstanding were eligible and were converted, we would have needed to issue 37,649 shares of Common Stock.

Fair Value Hedge Adjustment

On November 10, 2003, we entered into a fixed interest rate to floating interest rate swap agreement (the "Swap Agreement") covering a notional amount of debt of $240 million. We designated this swap as a fair value hedge of a portion of our 6.625% Notes. We used the Swap Agreement to reduce interest expense and modify exposure to interest rate risk by converting our fixed rate debt to a floating rate liability. The Swap Agreement was originally scheduled to terminate on November 15, 2010, however, on December 9, 2005, we notified the swap counterparty that we were exercising our right to terminate the Swap Agreement because of anticipated increases in the variable interest rate component of the swap. We paid a $7.9 million termination payment to the swap counterparty on December 13, 2005. The termination payment, which is reflected in the table above as Fair value hedge adjustment, will be amortized into Interest expense through November 15, 2010.

Asset-Based Lending Arrangement

On August 15, 2006, we entered into an amended and restated asset-based revolving credit facility, which provides for available borrowings, including letters of credit of up to $175 million, depending on the level of eligible inventory and accounts receivables. The previous credit limit was $130 million, including a $100 million sublimit for letters of credit. As of December 31, 2006, this facility supported $64.2 million of letters of credit and there were no outstanding borrowings under this facility. Any future borrowings under this facility will be variable rate borrowings, based on the applicable LIBOR rate for the specified rate reset period, plus an applicable margin. As of December 31, 2006, the applicable margin to LIBOR was 150 basis points.

The facility is secured by our accounts receivable, eligible coal inventories located at our facilities and on consignment at customers' facilities, and other intangibles. At December 31, 2006, total remaining availability was $110.8 million based on qualifying inventory and accounts receivable. The credit facility expires in August 2011.

This facility contains a number of significant restrictions and covenants that limit our ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) make distributions from subsidiaries.

Debt Maturity

The aggregate amounts of scheduled long-term debt maturities, including capital lease obligations, subsequent to December 31, 2006 are as follows:

	(In Thousands)
2007	$ 2,583
2008	1,846
2009	1,947
2010	337,201
2011	2,655
Beyond 2011*	770,377

* The 4.75% Notes and the 2.25% Notes in the amounts of $0.7 million and $9.6 million, respectively, included herein may be redeemed at the option of the holders in 2009 and 2011, respectively.

Total interest paid for the years ended December 31, 2006, 2005 and 2004, was $75.0 million, $56.1 million and $54.0 million, respectively.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, 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 the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

We use surety bonds to secure reclamation, workers' compensation, wage payments, and other miscellaneous obligations. As of December 31, 2006, we had $337.5 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $307.4 million, workers' compensation bonds of $10.0 million, wage payment and collection bonds of $8.7 million and other miscellaneous obligation bonds of $11.4 million.

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral. As of December 31, 2006, we had secured $42.2 million of surety obligations with letters of credit.

From time to time we use bank letters of credit to secure obligations for worker's compensation programs, various insurance contracts and other obligations. The Office of Workers' Claims for the Commonwealth of Kentucky has applied a new actuarial methodology for deriving surety obligation for existing claims, which has resulted in an assessment of an additional $37.1 million of surety. We have protested the assessment and, pending final resolution of the protest, the requirement for additional surety has been stayed. Any additional surety that is ultimately required will likely be satisfied with a bank letter of credit.

At December 31, 2006, we had $164.2 million of letters of credit outstanding (including the $42.2 million noted above that secure surety obligations), of which $100.0 million was collateralized by $105.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and $64.2 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2006.

7. Income Taxes

Income tax expense (benefit) included in the Consolidated Statements of Income is as follows:

	Year Ended		
	December 31, 2006	December 31, 2005	December 31, 2004
	(In Thousands)		
Current:			
Federal	$ 20,694	$ 2,852	$ (20,691)
State and local	95	117	15
Total current	20,789	2,969	(20,676)
Deferred:			
Federal	(15,439)	21,773	518
State and local	(1,942)	1,486	663
Total deferred	(17,381)	23,259	1,181
Total Income tax expense (benefit)	$ 3,408	$ 26,228	$ (19,495)

A reconciliation of Income tax expense (benefit) calculated at the federal statutory rate of 35% to our Income tax expense (benefit) on Net income (loss) is as follows:

	Year Ended		
	December 31, 2006	December 31, 2005	December 31, 2004
	(In Thousands)		
U.S. statutory federal tax expense (benefit)	$ 15,758	$ (26,394)	$ (1,975)
Increase (Decrease) resulting from:			
State taxes	(2,393)	1,322	379
Items without tax effect	1,091	609	688
Depletion	(25,897)	(29,932)	(24,257)
Non-deductible deferred compensation payout	1,279	9,653	-
Non-deductible debt restructuring costs	-	71,737	-
Extraterritorial excluded income	(797)	(1,160)	(1,622)
Valuation allowance adjustment	16,066	5,309	15,842
Reserve reduction	(1,197)	(4,284)	(7,300)
Other, net	(502)	(632)	(1,250)
Income tax expense (benefit)	$ 3,408	$ 26,228	$ (19,495)

Deferred taxes reflect the tax effects of differences between the amounts recorded as assets and liabilities for financial reporting purposes and the amounts recorded for income tax purposes. The tax effects of significant temporary differences giving rise to deferred tax assets and liabilities are as follows:

	Year Ended	
	December 31, 2006	December 31, 2005
	(In Thousands)	
Deferred tax assets:		
Postretirement benefit obligations	$ 68,555	$ 41,553
Workers' compensation	21,456	17,951
Reclamation and mine closure	51,440	47,254
Alternative minimum tax credit carryforwards	135,103	120,245
Accounting change on post-production stripping costs	59,970	-
Potential litigation	18,103	17,791
Deferred compensation	17,812	15,458
State net operating loss	14,204	14,204
Other, net	10,768	20,829
Total deferred tax assets	397,411	295,285
Valuation allowance for deferred tax assets	(147,178)	(127,510)
Total deferred tax assets, net of valuation allowance	250,233	167,775
Deferred tax liabilities:		
Plant, equipment and mine development	(249,861)	(237,870)
Mining property and mineral rights	(107,267)	(130,091)
Other	(9,795)	(13,433)
Total deferred tax liablities	(366,923)	(381,394)
Net deferred tax	$ (116,690)	$ (213,619)

Deferred tax assets include alternative minimum tax ("AMT") credits of $135.1 million and $120.2 million at December 31, 2006 and 2005, respectively, and net state net operating loss ("NOL") carryforwards of $14.2 million as of December 31, 2006 and 2005. The AMT credits have no expiration date. State NOL carryforwards begin to expire in 2016. We have recorded a valuation allowance for a portion of deferred tax assets that management believes, more likely than not, will not be realized. These deferred tax assets include AMT credits and state NOL that will likely not be realized at the maximum effective tax rate. In addition, we have generated additional state NOLs in prior years of $16.5 million that expire over various periods that have not been recorded as we believe the possibility of benefiting from such amounts is remote. This deferred tax asset would be offset in full by a valuation allowance if recorded.

We establish reserves for tax contingencies when, despite the belief that our tax return positions are fully supported, certain positions are likely to be challenged and may not be fully sustained. We establish the reserves based upon management's assessment of exposure associated with permanent tax differences (i.e., tax depletion expense), tax credits and interest expense applied to temporary difference adjustments. The tax reserves are analyzed at least annually and adjustments are made based upon changes in facts and circumstances, such as the progress of federal and state audits, case law and emerging legislation. During 2006, we reduced our tax reserve by $1.2 million, reflecting the reduction in exposure due to the notification of no exceptions from the IRS of a prior statutory period, partially offset by additional exposures identified for the current tax year. During 2005, we reduced our tax reserve by $4.3 million, reflecting the reduction in exposure due to the closing of prior period audits by state taxing authorities and the closing of a federal statutory period, partially offset by additional exposures identified for the 2005 tax year. Payments for federal taxes and state taxes of $63,000 and $1,063,000 were applied against the reserve during the years ended December 31, 2006 and 2005, respectively, as a result of audits of prior periods.

The IRS has examined our federal income tax returns, or statutes of limitations have expired through 2000. We are currently under audit from the IRS for the fiscal year ended October 31, 2001 and calendar years ended December 31, 2003 and 2004. Management believes that we have adequately provided for any income taxes and interest that may ultimately be paid with respect to all open tax years.

In June 2006, the FASB issued FIN 48, which prescribes a more-likely-than-not threshold for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. It also provides guidance on derecognition of income tax assets and liabilities, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties associated with tax positions, accounting for income taxes in interim periods, and income tax disclosures. FIN 48 is effective as of January 1, 2007 and the cumulative effects of applying it will be recorded as an adjustment to retained earnings and other accounts as applicable. We are currently assessing the potential impact of the statement on our financial position and results of operations.

8. Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
Reclamation (Note 9)	$ 142,687	$ 139,314
Other postretirement benefits (Note 10)	138,109	101,565
Workers' compensation and black lung (Note 11)	89,227	97,985
Other	99,831	111,561
Total other noncurrent liabilities	$ 469,854	$ 450,425

9. Reclamation

Our reclamation liabilities primarily consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with federal and state reclamation laws as defined by each mine permit. The obligation and corresponding asset are recognized in the period in which the liability is incurred.

We estimate our ultimate reclamation liability based upon detailed engineering calculations of the amount and timing of the future cash flows to perform the required work. We consider the estimated current cost of reclamation and apply inflation rates and a third party profit, as necessary. The third party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing.

The following table describes all changes to our reclamation liability:

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In Thousands)	
Reclamation liability at beginning of period	$ 156,776	$ 152,667
Accretion expense	10,166	10,156
Liability assumed/incurred	-	6,580
Liability disposed	-	(10,421)
Revisions in estimated cash flows	9,217	1,652
Payments	(4,205)	(3,858)
Reclamation liability at end of period	171,954	156,776
Less amount included in Other current liabilities	29,267	17,462
Total noncurrent liability	$ 142,687	$ 139,314

Liability disposed for the year ended December 31, 2005, included approximately $10.1 million of reclamation costs associated with the sale of our ownership interest in Big Elk Mining Company in the first quarter of 2005 (see Note 4 for further discussion). Liability assumed for the year ended December 31, 2005, includes approximately $5.8 million of reclamation costs associated with the acquisition of the primary assets of Great Western Coal, Inc., through a bankruptcy sale process, made in the second quarter of 2005.

10. Other Postretirement Benefits

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union employees. To be eligible, retirees must meet certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits and retiree contributions. Service costs are accrued currently based on an annual study prepared by independent actuaries. These plans are unfunded.

Net periodic postretirement benefit cost includes the following components:

	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
		(In Thousands)	
Service cost	$ 3,758	$ 3,607	$ 4,474
Interest cost	7,959	6,926	7,650
Amortization of net loss	2,307	1,704	2,023
Amortization of prior service credit	(750)	(2,651)	(685)
Net periodic postretirement benefit cost	$ 13,274	$ 9,586	$ 13,462

The discount rates assumed to determine the net periodic postretirement benefit cost were 5.75%, 5.75% and 6.25% for the years ended December 31, 2006, 2005 and 2004, respectively.

The following table sets forth the change in benefit obligation of our postretirement benefit plans:

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 135,999	$ 125,786
Service cost	3,758	3,607
Interest cost	7,959	6,926
Plan amendment	-	(3,854)
Actuarial loss	1,985	8,343
Benefits paid	(5,376)	(4,809)
Benefit obligation at the end of the period	$ 144,325	$ 135,999
Funded status	$ (144,325)	$ (135,999)
Unrecognized net actuarial loss	-	38,739
Unrecongized prior service credit	-	(9,801)
Accrued postretirement benefit obligation	(144,325)	(107,061)
Amount included in Other current liabilities	6,216	5,496
Postretirement benefit obligation included in Other noncurrent liabilities	$ (138,109)	$ (101,565)

As discussed in Note 1, we adopted SFAS 158 on December 31, 2006. According to the adoption provisions, we recognized the funded status of the postretirement medical benefit plans in the Consolidated Balance Sheet, increasing Accumulated other comprehensive loss by $29.4 million, excluding deferred tax effect of $11.5 million.

The table below details the changes pertaining to the postretirement benefit plans to the Consolidated Balance Sheet due to the adoption of SFAS 158:

	December 31, 2006 (In Thousands)		
	Before Application of SFAS 158	Adjustments	After Application of SFAS 158
Other current liabilities	$ (6,216)	$ -	$ (6,216)
Other noncurrent liabilities	(108,743)	(29,366)	(138,109)
Deferred income tax asset	-	11,453	11,453
Accumulated other comprehensive loss	-	17,913	17,913

Included in Accumulated other comprehensive loss prior to any deferred tax effects as of December 31, 2006, is $38.4 million of net actuarial loss and $9.1 million of prior service credit. We expect to recognize $0.8 million of prior service credit and $0.6 million of net actuarial loss in 2007.

The discount rates used to determine the benefit obligations as of the end of each year are as follows:

	December 31, 2006	December 31, 2005
Discount rates	5.90%	5.75%
Measurement date	12/31/2006	12/31/2005

The assumed health care cost trend rates used to determine the benefit obligation as of the end of each year are as follows:

	December 31, 2006	December 31, 2005
Health care cost trend rate for next year	8.20%	9.00%
Ultimate trend rate	5.00%	5.00%
Year that the rate reaches ultimate trend rate	2011	2011

Assumed health care cost trend rates have a significant effect on the amounts reported for the medical plans. A one-percentage point change in assumed health care cost trend rates would have the following effects:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In Thousands)	
Effect on total of service and interest costs components	$ 2,032	$ (1,624)
Effect on accumulated postretirement benefit obligation	$ 22,140	$ (18,042)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the periods noted ("without subsidy" represents expected payments had the Medicare subsidy not been introduced):

	Expected Benefit Payments	
	With Subsidy	Without Subsidy
	(In Thousands)	
2007	$ 6,216	$ 6,529
2008	6,785	7,122
2009	7,408	7,767
2010	7,959	8,346
2011	8,635	9,041
Years 2012 to 2016	48,544	51,066

In 2005, we amended our postretirement benefit plans, effective January 1, 2006, to make all employees eligible for postretirement health benefits. Previously, employees hired after August 1, 2003 were not eligible for postretirement health benefits. This plan amendment makes all employees eligible for our Medicare Supplement Plan, provided they meet applicable age and service requirements.

Multi-Employer Benefits

Under the Coal Act, coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the UMWA Benefit Funds. Based on available information at December 31, 2006, our obligation under the Coal Act was estimated at approximately $24.1 million, compared to our estimated obligation at December 31, 2005 of $54.1 million. The obligation was discounted using a 5.00% rate each year. We treat our obligation under the Coal Act as participation in a multi-employer plan and record the cost of our obligation as expense as payments are assessed. The expense related to this obligation for the years ended December 31, 2006, 2005 and 2004 totaled $4.3 million, $4.8 million and $6.7 million, respectively.

On December 20, 2006, President Bush signed the Tax Relief and Retiree Health Care Act of 2006. This legislation includes important changes to the Coal Act that impacts all companies required to contribute to the UMWA Combined Benefit Fund ("CBF"). Effective October 1, 2007, the Social Security Administration ("SSA") will revoke all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies") but their premium relief is phased-in. The reachback companies will pay their full premium obligation in the current plan year that ends September 30, 2007. However, they will pay only 55% of their plan year 2008 assessed premiums, 40% of their plan year 2009 assessed premiums, and 15% of their plan year 2010 assessed premiums. General U.S. Treasury money will be transferred to the CBF to make up the difference. After 2010, reachback companies will have no further obligations to the CBF, and transfers from the U.S. Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies.

11. Workers' Compensation and Black Lung Benefits

Workers' compensation and black lung benefit obligation consisted of the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
Accrued self-insured black lung obligation	$ 53,284	$ 69,497
Workers' compensation (traumatic injury)	56,042	51,526
Total accrued workers' compensation and black lung	109,326	121,023
Less amount included in Other current liabilities	20,099	23,038
Workers' compensation & black lung in Other noncurrent liabilities	$ 89,227	$ 97,985

The amount of workers' compensation (traumatic liability) related to self-insurance was $52.3 million and $44.0 million at December 31, 2006 and 2005, respectively. Weighted average actuarial assumptions used in the determination of the self-insured portion of workers' compensation (traumatic injury) liability at December 31, 2006 and 2005 included a discount rate of 5.00% and the accumulated black lung obligation included a discount rate of 5.90% and 5.75% at December 31, 2006 and 2005, respectively.

A reconciliation of changes in the self-insured black lung obligation is as follows:

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In Thousands)	
Beginning of year accumulated black lung obligation	$ 50,779	$ 71,656
Service cost	2,619	2,392
Interest cost	2,861	2,694
Actuarial gain	(1,601)	(23,596)
Benefit payments	(1,374)	(2,367)
End of year accumulated black lung obligation	53,284	50,779
Unamortized net gain	-	18,718
Accrued self-insured black lung obligation	$ 53,284	$ 69,497

As discussed in Note 1, we adopted SFAS 158 on December 31, 2006. According to the adoption provisions, we recognized the accumulated black lung obligation in the Consolidated Balance Sheet, decreasing the black lung liability by $16.6 million to $53.3 million ($50.3 million in Other noncurrent liabilities at December 31, 2006 and $3.0 million in Other current liabilities). The $16.6 million decrease has been recorded in Accumulated other comprehensive loss, net of tax.

The table below details the changes to the Consolidated Balance Sheet due to the adoption of SFAS 158:

	December 31, 2006 (In Thousands)		
	Before Application of SFAS 158	Adjustments	After Application of SFAS 158
Other current liabilities	$ (2,991)	$ -	$ (2,991)
Other noncurrent liabilities	(66,853)	16,560	(50,293)
Deferred income taxes	-	(6,458)	(6,458)
Accumulated other comprehensive loss	-	(10,102)	(10,102)

Included in Accumulated other comprehensive loss prior to any deferred tax effects as of December 31, 2006, is a net actuarial gain of $16.6 million, of which we expect to recognize $3.3 million in 2007.

Expenses for black lung benefits and workers' compensation related benefits include the following components:

	Year Ended December 31, 2006	December 31, 2005	December 31, 2004
		(In Thousands)	
Self-insured black lung benefits:			
Service cost	$ 2,619	$ 2,392	$ 3,333
Interest cost	2,861	2,694	3,886
Amortization of actuarial gain	(3,759)	(4,691)	(461)
	1,721	395	6,758
Other workers' compensation benefits	36,381	40,609	40,111
	$ 38,102	$ 41,004	$ 46,869

Payments for benefits, premiums and other costs related to black lung and workers' compensation liabilities were $33.2 million, $39.9 million and $36.2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

The actuarial assumptions used in the determination of self-insured black lung benefits expense included discount rates of 5.75%, 5.75% and 6.25% for the years ended December 31, 2006, 2005 and 2004, respectively.

In 2005, our independent actuaries completed an experience study on historical claims approval rates, incidence rates and the percentage of federal versus state (West Virginia and Kentucky) awarded claims. After reviewing the study, we adjusted our black lung assumptions to reflect recent historical disability incidence rates and claims approval rates. These adjustments decreased the January 1, 2005 black lung accumulated benefit obligation by approximately $21 million. Such decreases in the liability are included in the actuarial gains and losses and recognized in the determination of the black lung expense over a five-year period.

Our self-insured black lung obligation is calculated using assumptions regarding future medical cost increases and cost of living increases. Federal black lung benefits are subject to cost of living increases. State benefits increase only until disability, and then remain constant. We assume a 6.5% annual medical cost increase and a 3.0% cost of living increase in determining our black lung obligation and the annual black lung expense. Assumed medical cost and cost of living increases significantly affect the amounts reported for our black lung expense and obligation. A one-percentage point change in each of assumed medical cost and cost of living trend rates would have the following effects:

	1-Percentage Point Increase		1-Percentage Point Decrease	
Increase/decrease in medical cost trend rate:				
Effect on total of service and interest costs components	$	159	$	(125)
Effect on accumulated black lung obligation	$	1,107	$	(896)
Increase/decrease in cost of living trend rate:				
Effect on total service and interest cost components	$	813	$	(641)
Effect on accumulated black lung obligation	$	6,478	$	(5,247)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid related to the self-insured black lung obligation:

	Expected Benefit Payments (In Thousands)	
2007	$	2,991
2008		3,095
2009		3,207
2010		3,330
2011		3,464
Years 2012 to 2016		19,206

12. Stock Plans

Description of Stock Plans

The Massey Energy Company 2006 Stock and Incentive Compensation Plan (the "2006 Plan") became effective on June 28, 2006 upon certification by the independent inspectors of election of the voting results on all the proposals that came before the shareholders at our Annual Meeting of Shareholders held on May 16, 2006. The 2006 Plan replaces the five stock-based compensation plans (the "Prior Plans") we had in place prior to the approval of the 2006 Plan, all of which had been approved by our shareholders. The Prior Plans include the Massey Energy Company 1996 Executive Stock Plan, as amended and restated effective November 30, 2000 (the "1996 Plan"), the Massey Energy Company 1997 Stock Appreciation Rights Plan, as amended and restated effective November 30, 2000 (the "SAR Plan"), the Massey Energy Company 1999 Executive Performance Incentive Plan, as amended and restated effective November 30, 2000 (the "1999 Plan"), the Massey Energy Company Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1995 Plan"), and the Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1997 Plan"). Stock-based compensation has been granted under the 2006 Plan and the Prior Plans in the manner described below. Issued and outstanding stock-based compensation has been granted to officers and certain key employees in accordance with the provisions of the 1996 Plan, the SAR Plan, the 1999 Plan, and the 2006 Plan. Issued and outstanding stock-based compensation has been granted to non-employee directors in accordance with the provisions of the 1995 Plan, the 1997 Plan and the 2006 Plan. The Compensation Committee of the Board of Directors administers the 1996 Plan, the 1999 Plan, the SAR Plan and the 2006 Plan. A committee comprised of non-participating board members administers the 1995 Plan and the 1997 Plan.

The 1996 Plan provided for grants of stock options and restricted stock. The 1999 Plan provided for grants of stock options, restricted stock, incentive awards and stock units. The SAR Plan provided for grants of SARs. The 1995 Plan provided for grants of restricted stock and restricted units. The 1997 Plan provided for grants of restricted stock. As of June 28, 2006, grants can no longer be made under the Prior Plans, except for the 1996 Plan, under which grants could no longer be made as of March 2, 2006. All awards previously granted that are outstanding under the Prior Plans will remain effective in accordance with the terms of their grant.

As of December 31, 2006, there were 516,421 shares of restricted stock outstanding and 2,795,041 stock options outstanding with a weighted average exercise term to expiration of 6.6 years and a weighted average exercise price of $19.83 per share, of which 1,079,970 were exercisable.

The aggregate number of shares of Common Stock that may be issued for future grant under the 2006 Plan as of December 31, 2006 was 2,728,256 shares, which was computed as the 3,500,000 shares specifically authorized in the 2006 Plan, less grants made in 2006, plus the number of shares that (i) were represented by restricted stock or unexercised vested or unvested stock options that previously have been granted and were outstanding under the Prior Plans as of June 28, 2006 and (ii) expire or otherwise lapse, are terminated or forfeited, are settled in cash, or are withheld or delivered to us for tax purposes at any time after June 28, 2006. The 2006 Plan provides for grants of stock options, SARs, restricted stock, restricted units, unrestricted stock and incentive awards.

Accounting for Stock-Based Compensation

Total compensation expense recognized for stock-based compensation during the year ended December 31, 2006, 2005 and 2004 was $7.3 million, $23.1 million and $29.7 million, respectively. The total income tax benefit recognized in the consolidated statement of income for share based compensation arrangements during the year ended December 31, 2006, 2005 and 2004 was approximately $2.8 million, $9 million and $11.6 million, respectively. We recognize compensation expense on a straight-line basis over the vesting period for the entire award for any awards with graded vesting.

As a result of adopting FAS 123R, we recognized non-cash stock-based compensation expense for stock options of approximately $6.1 million (pre-tax) in Selling, general and administrative expense for the year ended December 31, 2006. The total income tax benefit recognized on this compensation expense was approximately $2.4 million. Income before income taxes, Net income and Earnings per share for the year ended December 31, 2006 were $6.1 million, $3.7 million and $0.05 lower, respectively, than if we had continued to account for share-based compensation under APB No. 25. As of December 31, 2006, there was $15 million of total unrecognized compensation cost related to stock options expected to be recognized over a weighted-average period of approximately 2.4 years. In the year ended December 31, 2006, we also reflected $1.1 million of excess tax benefits as a financing cash flow in the consolidated statement of cash flows resulting from the exercise of stock options.

Prior to the adoption of FAS 123R, we accounted for stock options in accordance with APB No. 25, under which no compensation expense was recorded because the exercise price of stock options equaled the market price of the underlying stock on the date of grant. Had we adopted FAS 123R in prior periods, the impact of that statement would have approximated the impact of FASB Statement No. 123, "Accounting for Stock-based Compensation" (as if the fair-value-based recognition provisions of that statement had been applied) as shown in the following table:

	Year Ended	
	December 31, 2005	December 31, 2004
	(In Thousands, Except Per Share Amounts)	
Net (loss) income, as reported	$ (101,638)	$ 13,852
Deduct: Total stock-based employee compensation expense for stock options determined under Black-Scholes option pricing model (net of tax)	(3,959)	(2,138)
Pro forma net (loss) income	$ (105,597)	$ 11,714
(Loss) Income per share:		
Basic - as reported	$ (1.33)	$ 0.18
Basic - pro forma	$ (1.38)	$ 0.16
Diluted - as reported	$ (1.33)	$ 0.18
Diluted - pro forma	$ (1.38)	$ 0.15

Equity instruments

We have granted stock options to employees under the 2006 Plan, the 1999 Plan and the 1996 Plan. These options typically have a requisite service period of three to four years, though there are some awards outstanding with requisite service periods of one year up to four years. Vesting generally occurs ratably over a three or four-year period, though some stock options fully vest upon the earlier to occur of meeting certain performance criteria or four years from the date of grant. The maximum contractual term of stock options granted is 10 years.

We value stock options using the Black-Scholes valuation model, which employs certain key assumptions. We estimate volatility using both historical and market data over the contractual term of the options granted. The dividend yield is calculated on the current annualized dividend payment and the stock price at the date of grant. The expected term is based on historical data and exercise behavior. The risk-free interest rate is based on the zero-coupon treasury bond rate in effect at the date of grant.

During the year ended December 31, 2004, 474,320 stock options were granted with contractual terms of ten years and a weighted average grant date fair value of $13.67 per option. Assumptions included expected volatility of 55%, expected dividend yield of 0.5%, expected term of 4.3 years and a risk-free rate of 3.56%.

During the year ended December 31, 2005, 842,222 stock options were granted with contractual terms of ten years and a weighted average grant date fair value of $16.99 per option. Assumptions included expected volatility ranging from 53% to 55%, expected dividend yield ranging from 0.3% to 0.4%, expected term of 1.3 to 5 years and a risk-free rate ranging from 3.82% to 4.41%.

During the year ended December 31, 2006, 642,434 stock options were granted with contractual terms of ten years and a weighted average grant date fair value of $24.32 per option. Assumptions included expected volatility ranging from 46% to 55%, expected dividend yield ranging from 0.4% to 0.7%, expected term of 1.2 to 5.0 years and a risk free rate ranging from 4.82% to 4.85%.

A summary of option activity under the plans for the year ended December 31, 2006 is presented below:

	Number of Options	Weighted average exercise price	Weighted average contractual term (years)	Aggregate Intrinsic Value
	(In Thousands, Except Exercise Price and Contractual Term)			
Outstanding at December 31, 2005	2,486	$ 24.69		
Granted	642	24.32		
Exercised	(185)	11.61		
Forfeited/expired	(148)	26.38		
Outstanding at December 31, 2006	2,795	$ 19.83	6.6	$ 9,484
Exercisable at December 31, 2006	1,080	$ 20.87	5.0	$ 7,458

We received $2.1 million, $7.2 million and $11.9 million in cash proceeds from the exercise of stock options for the years ended December 31, 2006, 2005 and 2004, respectively. The intrinsic value of stock options exercised was $3.5 million, $12.8 million and $10.6 million for the years ended December 31, 2006, 2005 and 2004, respectively.

We have granted restricted stock to our employees under the 2006 Plan and 1999 Plan and to non-employee directors under the 1995 Plan and 1997 Plan. Restricted stock awards are valued on the date of grant based on the average of the high and low trading value. As of December 31, 2006, there was $10.3 million of unrecognized compensation cost related to restricted stock expected to be recognized over the next three years. With the adoption of FAS 123R, unearned compensation is recorded on a net basis in Additional capital.

A summary of the status of restricted stock at December 31, 2006, and changes for the year then ended is presented below:

(Shares in 000's)	Shares		Weighted average grant date fair value
Unvested at December 31, 2005	416	$	22.32
Granted	277	$	29.11
Vested	(139)	$	14.79
Forfeited	(38)	$	26.29
Unvested at December 31, 2006	516	$	27.71

The fair value of restricted stock vested during the years ended December 31, 2006, 2005 and 2004 was $3.6 million, $7.6 million and $7.3 million, respectively.

Liability instruments

We use the fair value method to recognize compensation cost associated with SARs. At both December 31, 2006 and 2005, there were 262,500 vested SARs outstanding and exercisable. The weighted average exercise price of these SARs was $29.19 per SAR; the weighted average contractual term was 6.8 years. In 2004, 675,000 SARs were settled for $6.3 million.

We also issue stock incentive units, which are classified as liabilities. They are settled with a cash payment for each unit vested, equal to the fair market value of Common Stock on the vesting date. During the year ended December 31, 2006, 411,372 incentive units were awarded and 80,261 incentive units were settled for $2.1 million.

13. Lease Obligations

We lease two office buildings and certain mining and other equipment under various lease agreements. Certain of these leases provide options for the purchase of the property at the end of the initial lease term, generally at its then fair market value, or to extend the terms at its then fair rental value. Certain of these leases contain financial covenants that may require an accelerated buyout of the lease if the covenants are violated. Rental expense for the years ended December 31, 2006, 2005 and 2004 was $46.4 million, $42.4 million and $44.2 million, respectively.

During 2006, we sold and leased-back certain mining equipment. We received net proceeds of $21.8 million with no resulting gain or loss on the transaction. At lease termination, the leases contain renewal and purchase options at an amount approximating fair value. The leases are being accounted for as operating leases.

During 2005, we sold and leased-back certain mining and other equipment in several transactions. We received net proceeds of $71.7 million, resulting in net gains of $4.1 million, which were deferred. The gains are being recognized ratably over the term of the leases, which range from 3.5 to 8 years. At lease termination, the leases contain renewal and purchase options at an amount approximating fair value. The leases are being accounted for as operating leases.

During 2004, we generated $15.0 million of cash from a sale-leaseback (capital lease) transaction of certain mining equipment with no resulting gain or loss on the transaction. We also entered into an additional $27.3 million of capital leases for mining equipment. The leases are for periods ranging from approximately 2 to 3 years with no residual value guarantee.

The following presents future minimum rental payments, by year, required under leases with initial terms greater than one year, in effect at December 31, 2006:

	Capital Leases	Operating Leases
	(In Thousands)	
2007	$ 3,095	$ 26,308
2008	2,256	34,025
2009	2,256	31,391
2010	2,395	26,106
2011	2,655	17,221
Beyond 2011	-	14,117
Total minimum lease payments	12,657	$ 149,168
Less imputed interest	1,425	
Present value of minimum capital lease payments	$ 11,232	

14. Appalachian Synfuel, LLC

Appalachian Synfuel, LLC ("Appalachian Synfuel") was formed in 1997. As a provider of synthetic fuel, Appalachian Synfuel generates tax credits pursuant to Section 45K (formerly Section 29) of the IRC for its owners; however, because of our tax position we are unable to utilize the tax credits generated by Appalachian Synfuel. In order to monetize the value of our investment, we sought to sell an interest in Appalachian Synfuel to an entity that could benefit currently from the tax credits generated. In order to facilitate such a transaction, the synfuel operating agreement was amended to divide the ownership interest in three tranches, Series A, Series B and Series C.

Under the amended Appalachian Synfuel agreement, the Series A owner generally is entitled to the risks and rewards of the first 475,000 tons of production, including the right to the related tax credits. The Series B owner is generally entitled to the risks and rewards of all excess production up to the rated capacity of 1.2 million tons. The Series C owner is responsible for providing recourse working capital loans to Appalachian Synfuel going forward at a specified indexed interest rate. As a result, the Series C owner will fund the daily operations of Appalachian Synfuel. The Series C owner also has the responsibility at the end of the term of the Appalachian Synfuel agreement to wind up the affairs of Appalachian Synfuel, disposing of all assets and settling liabilities.

We sold 99% of the Series A and Series B interest in Appalachian Synfuel in 2001 and 2002 and received cash of $7.2 million, a recourse promissory note for $34.6 million that is being paid in quarterly installments of $1.9 million including interest, and a contingent promissory note that is paid on a cents per Section 45 credit dollar earned based on synfuel tonnage shipped. The payments to be received under the contingent promissory note may be reduced or eliminated if the price of oil remains above a certain threshold price set by the IRS (the "threshold price"). Once the threshold price is reached, the Section 45K credits will be phased out ratably over a $13.50 per barrel range above the threshold price. The threshold price for 2006 is expected to be set by the IRS in April 2007. For fiscal year 2006, the average price of West Texas Intermediate crude oil was approximately $66.09 per barrel. At this price level a portion of the Section 45K credits for 2006 will likely be phased out, which reduced the amount of income we accrued in 2006 from payments to be received under the contingent promissory note. Deferred gains of $4.8 million and $9.5 million as of December 31, 2006 and 2005, respectively, are included in Other noncurrent liabilities. The $4.8 million will be recognized in 2007. Our subsidiary, Marfork Coal Company, Inc., manages the facility under an operating agreement.

15. Concentrations of Credit Risk and Major Customers

We are engaged in the production of coal for the electric utility industry, steel industry and industrial customers. Electric utility coal sales accounted for approximately 62%, 60% and 56% of Produced coal revenue for the years ended December 31, 2006, 2005 and 2004, respectively. Metallurgical coal sales accounted for approximately 28%, 29% and 33% of Produced coal revenue for the years ended December 31, 2006, 2005 and 2004, respectively. Industrial coal sales for the years ended December 31, 2006, 2005 and 2004 were 10%, 11% and 11% of Produced coal revenue, respectively.

Our mining operations are conducted in southern West Virginia, eastern Kentucky and western Virginia. Our coal is marketed primarily in the U.S.

For the years ended December 31, 2006, 2005 and 2004, approximately 11%, 13% and 10%, respectively, of Produced coal revenue was attributable to sales to affiliates of American Electric Power Company, Inc. For the years ended December 31, 2005 and 2004, approximately 12% and 13%, respectively, of Produced coal revenue was attributable to sales to affiliates of DTE Energy Corporation. At December 31, 2006, approximately 55%, 28% and 17% of Trade and other accounts receivable represents amounts due from utility customers, metallurgical customers and industrial customers, respectively, compared with 65%, 16% and 19%, respectively, as of December 31, 2005.

Our Trade and other accounts receivable are subject to potential default by customers. In prior years, certain of our customers have filed for bankruptcy resulting in bad debt charges. In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or events may trigger the application of tighter terms of sale, requirements for collateral or, ultimately, a suspension of credit privileges. We establish bad debt reserves to specifically consider customers in financial difficulty and other potential receivable losses. In establishing the reserve, we consider the financial condition of individual customers and probability of recovery in the event of default. We charge off uncollectible receivables once legal potential for recovery is exhausted.

16. Fair Value of Financial Instruments

We used the following methods and assumptions to estimate our fair value disclosures for financial statements as of December 31, 2006 and 2005:

Cash and cash equivalents: The carrying value approximates the fair value due to the short maturity of these instruments.

Long-term debt: At December 31, 2006, the combined fair value estimate of our 6.875% Notes, 6.625% Notes, 2.25% Notes and 4.75% Notes outstanding was $1,063.8 million based on available market information at that date. At December 31, 2005, the combined fair value estimate of our 6.875% Notes, 6.625% Notes, 2.25% Notes and 4.75% Notes outstanding was $1,123.5 million based on available market information at that date.

Capital lease obligations: The fair value estimate of our capital lease obligations at December 31, 2006 and 2005 is based on estimated borrowing rates used to discount the cash flows to their present value. At December 31, 2006 and 2005, the fair value estimate of capital lease obligations was $10.8 million and $20.5 million, respectively.

17. Contingencies and Commitments

Harman

In December 1997, A.T. Massey's then subsidiary, Wellmore Coal Corporation ("Wellmore"), declared force majeure under its coal supply agreement with Harman Mining Corporation ("Harman") and reduced the amount of coal to be purchased from Harman. On October 29, 1998, Harman and its sole shareholder sued A.T. Massey and five of its other subsidiaries ("Massey Defendants") in the Circuit Court of Boone County, West Virginia, alleging that the Massey Defendants tortiously interfered with Wellmore's agreement with Harman, causing Harman to go out of business. On August 1, 2002, the jury awarded the plaintiffs $50 million in compensatory and punitive damages. On October 24, 2006, the Massey Defendants timely filed their Petition for Appeal to the Supreme Court of Appeals of West Virginia. As of December 31, 2006, we had accrued a liability of $31.7 million, including $9.7 million of interest, which is included in Other current liabilities.

West Virginia Flooding

Since July 2001, we and nine of our subsidiaries have been sued in 17 consolidated civil actions filed in the Circuit Courts of Boone, Fayette, Kanawha, McDowell, Mercer, Raleigh and Wyoming Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about July 8, 2001. Along with 32 other consolidated cases not involving us or our subsidiaries, these cases cover approximately 4,300 plaintiffs seeking unquantified compensatory and punitive damages from approximately 180 defendants. The Supreme Court of Appeals of West Virginia transferred all 49 cases to the Circuit Court of Raleigh County, West Virginia, to be handled by a mass litigation panel of three judges. The panel judges will hold multiple trials, each relating to all or part of a watershed. On January 18, 2007, a panel judge dismissed all claims asserted by all plaintiffs within the Coal River watershed. We believe we have insurance coverage applicable to these items.

Since August 2004, six subsidiaries have been sued in seven civil actions filed in the Circuit Courts of Boone, McDowell, Mingo, Raleigh, Summers, and Wyoming Counties, West Virginia, for alleged property damage and personal injuries arising out of flooding on or about May 2, 2002. These complaints cover approximately 600 plaintiffs seeking unquantified compensatory and punitive damages from approximately 65 defendants.

Since May 2006, we and twelve of our subsidiaries have been sued in two civil actions filed in the Circuit Courts of Logan and Mingo Counties, West Virginia, for alleged property damage and personal injuries arising out of flooding between May 30 and June 4, 2004. These complaints cover approximately 400 plaintiffs seeking unquantified compensatory and punitive damages from approximately 55 defendants.

We believe these matters will be resolved without a material impact on our cash flows, results of operations or financial condition.

West Virginia Trucking

Since January 2003, an advocacy group and residents in Boone, Kanawha, Mingo and Raleigh Counties, West Virginia, filed 17 suits in the Circuit Courts of Kanawha and Mingo Counties, West Virginia, against us and 12 of our subsidiaries. The claims against us and three of our subsidiaries were dismissed. Plaintiffs alleged that defendants illegally transported coal in overloaded trucks, causing damage to state roads, thereby interfering with plaintiffs' use and enjoyment of their properties and their right to use the public roads. Plaintiffs seek injunctive relief and compensatory and punitive damages. The Supreme Court of Appeals of West Virginia referred the consolidated lawsuits, and three similar lawsuits against other coal and transportation companies not involving our subsidiaries, to the Circuit Court of Lincoln County, West

Virginia, to be handled by a mass litigation panel of one judge. The cases are stayed while the question of whether private parties may sue for damages to public roads is certified to the Supreme Court of Appeals. We believe we have insurance coverage applicable to these items and that they will be resolved without a material impact on our cash flows, results of operations or financial condition.

Well Water Contamination

Since September 2004, approximately 725 plaintiffs filed approximately 360 suits against us and our subsidiary Rawl Sales & Processing Co. in the Circuit Court of Mingo County, West Virginia, for alleged property damage and personal injuries arising out of slurry injection and impoundment practices allegedly contaminating plaintiffs' water wells. Plaintiffs seek injunctive relief and unquantified compensatory and punitive damages. We believe we have insurance coverage applicable to these items and that they will be resolved without a material impact on our cash flows, results of operations or financial condition.

Wheeling-Pittsburgh Steel

On April 27, 2005, Wheeling-Pittsburgh Steel Corporation ("WPS") sued our subsidiary Central West Virginia Energy Company ("CWVE") in the Circuit Court of Brooke County, West Virginia, seeking (a) an order requiring CWVE to specifically perform alleged obligations under a Coal Supply Agreement and (b) compensatory damages due to CWVE's alleged failure to perform and alleged damages to WPS's coke ovens. WPS later amended its complaint to add Mountain State Carbon, LLC as a plaintiff, us as a defendant, and claims for bad faith, misrepresentation and punitive damages. While we believe we have sufficient legal reserves for this matter, it is possible that the actual outcome of the matter could vary significantly from this amount. We will continue to review the amount of the accrual and any adjustment required to increase or decrease the accrual based on development of the matter will be made in the period determined.

International Coal Group

On November 18, 2005, ICG, LLC ("ICG"), a subsidiary of International Coal Group, Inc., sued our subsidiary, Massey Coal Sales Company, Inc., d/b/a Massey Utility Sales Company ("MUS"), in the United States District Court for the Eastern District of Kentucky, seeking declaratory relief and compensatory and punitive damages due to MUS's alleged failure to deliver coal and related matters. On August 2, 2006, the federal court dismissed ICG's fraud claims and certain breach of contract claims, ruling there was no basis for punitive damages. On June 1, 2006, ICG also sued MUS, us, and our subsidiary, Sidney Coal company, Inc., in Circuit Court in Pike County, Kentucky, alleging tortious interference with a contract between ICG and its customer, seeking compensatory and punitive damages. We believe we have defenses to the claims and that these matters will be resolved without a material impact on our cash flows, results of operations or financial condition.

Other Legal Proceedings

We are parties to a number of other legal proceedings, incident to our normal business activities. These matters include contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition.

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Commitments

As of December 31, 2006, we had commitments to purchase $140.3 million of capital assets and other services during 2007.

18. Quarterly Information (Unaudited)

The table below details our quarterly financial information for the previous two fiscal years.

	Three Months Ended			
	March 31, 2006 (1)	June 30, 2006 (1)	September 30, 2006 (2)	December 31, 2006
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 559,469	$ 556,116	$ 555,897	$ 548,372
Income before interest and taxes	24,290	20,337	46,614	19,765
Income before taxes	7,617	3,882	30,197	3,328
Income before cumulative effect of accounting change	6,250	3,225	24,156	7,985
Net income	5,611	3,225	24,156	7,985
Income per share (basic and diluted):				
Income before cumulative effect of accounting change	$ 0.08	$ 0.04	$ 0.30	$ 0.10
Net income	$ 0.07	$ 0.04	$ 0.30	$ 0.10

	Three Months Ended			
	March 31, 2005 (3)	June 30, 2005	September 30. 2005 (4)	December 31, 2005 (5)
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 570,025	$ 582,535	$ 533,743	$ 517,955
Income (Loss) before interest and taxes	71,775	51,526	41,911	(186,161)
Income (Loss) before taxes	58,531	41,211	30,289	(205,441)
Net income (loss)	50,627	37,010	22,523	(211,798)
Income (Loss) per share:				
Basic	$ 0.67	$ 0.48	$ 0.29	$ (2.76)
Diluted	$ 0.59	$ 0.44	$ 0.28	$ (2.76)

(1) During January 2006, our Logan County resource group's Aracoma longwall mine experienced a fire. The mine returned to operational status in July 2006. Costs related to the fire were approximately $5.3 million in the first quarter and $6.4 million in the second quarter.

(2) Income for the third quarter of 2006 includes a $30 million pre-tax gain for the sale of our Falcon reserves (see Note 4 for further information).

(3) Income for the first quarter of 2005 includes a charge of $9.1 million pre-tax related to an adjustment of legal reserves and a $34.0 million pre-tax gain for the sale of our ownership interest in Big Elk Mining Company (see Note 4 for further information).

(4) Income for the third quarter of 2005 includes a non-cash gain of $38.2 million pre-tax on a coal reserves exchange (see Note 4 for further information) and a net favorable adjustment of $4.1 million pre-tax due to a decrease in legal reserves for certain legal matters.

(5) Loss for the fourth quarter of 2005 includes a charge of $219.0 million pre-tax related to our debt repurchase and exchange offer (see Note 6 for further information) and a gain of $11.9 million pre-tax upon the early repayment of $27.0 million related to a note receivable from the March 31, 2005 sale of the our ownership interest in Big Elk Mining Company (see Note 4 for further information).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

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

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures and Changes in Internal Control Over Financial Reporting

We have established disclosure controls and procedures to ensure that information relating to us, including our consolidated subsidiaries, required to be disclosed in the reports that we file or submit under the Exchange Act, is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Based on our evaluation as of December 31, 2006, the principal executive officer and principal financial officer have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that the information required to be disclosed in reports that we file or furnish under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2006, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control over financial reporting report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and assesses the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Massey Energy Company ("Massey") is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Massey'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.

Massey's internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Massey; (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 are being made only in accordance with authorizations of management and the directors of Massey; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Massey's assets that could have a material effect on the Company's 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.

Massey's management assessed the effectiveness of Massey's internal control over financial reporting as of December 31, 2006. In making this assessment, Massey used the criteria in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment based on those criteria, Massey's management has concluded that, as of December 31, 2006, internal control over financial reporting is effective.

The Company's management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which follows immediately hereafter.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Massey Energy Company

We have audited management's assessment, included in the accompanying Management Report on Internal Control over Financial Reporting, that Massey Energy Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Massey Energy Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management's assessment that Massey Energy Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Massey Energy Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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 Massey Energy Company as of December 31, 2006 and 2005, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2006 of Massey Energy Company and our report dated February 28, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Richmond, Virginia
February 28, 2007

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated by reference from our definitive proxy statement pursuant to Regulation 14A, which will be filed not later than 120 days after the close of Massey's fiscal year ended December 31, 2006:

- Information regarding the directors required by this item is found under the heading *Election of Directors*.
- The information concerning the executive officers of Massey required by this item is included in Part I, Item 1, of this Form 10-K.
- Information regarding Massey's Audit Committee required by this item is found under the heading *Committees of the Board*.
- Information regarding Section 16(a) Beneficial Ownership Reporting Compliance required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance*.
- Information regarding Massey's Code of Ethics required by this item is found under the heading *Code of Ethics*.

Because Common Stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of July 10, 2006. In addition, we have filed, as exhibits to this annual report on Form 10-K, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Item 11. Executive Compensation

Information required by this item is included in the *Executive Compensation and Other Information* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2006.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item is included in the *Stock Ownership of Directors and Executive Officers, Stock Ownership of Certain Beneficial Owners,* and *Equity Compensation and Other Information* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2006.

The following table sets forth as of December 31, 2006, the number of shares of Common Stock authorized for issuance under our equity compensation plan.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average per share exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders	2,795,041	$19.83	2,728,256
Equity compensation plans not approved by shareholders	-	-	-
Total	2,795,041	$19.83	2,728,256

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is included in the *Transactions with Related Persons, Promoters and Certain Control Persons* section of the *Election of Directors* portion of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2006.

Item 14. Principal Accountant Fees and Services

Information concerning principal accountant fees and services contained under the heading *The Audit Committee Report* in the definitive proxy statement pursuant to Regulation 14A, which is incorporated by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2006.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report:

1. Financial Reports:

   Consolidated Statements of Income for the Fiscal Years Ended December 31, 2006, 2005, and 2004

   Consolidated Balance Sheets at December 31, 2006 and 2005

   Consolidated Statements of Cash Flows for the Fiscal Years Ended December 31, 2006, 2005, and 2004

   Consolidated Statements of Shareholders' Equity for the Fiscal Years Ended December 31, 2006, 2005, and 2004

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules: Except as set forth below, all schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the Consolidated Financial Statements and Notes thereto.

   Schedule II—Valuation and Qualifying Accounts

3. Exhibits:

Exhibit No.	Description
3.1	Certificate of Ownership and Merger merging Massey Energy Company with and into Fluor Corporation accompanied by Restated Certificate of Incorporation of Massey Energy Company, as amended [filed as Exhibit 3.1 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
3.2	Restated Bylaws (as amended as of June 27, 2006) of Massey Energy Company [filed as Exhibit 3.i to Massey's current report on Form 8-K filed June 30, 2006 and incorporated by reference]
4.1	Senior Indenture, dated May 29, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors and Wilmington Trust Company, as Trustee, in connection with the Company's 4.75% Convertible Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed May 30, 2003 and incorporated by reference]
4.2	First Supplemental Indenture, dated May 29, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, supplementing that certain Senior Indenture dated May 29, 2003, in connection with the Company's 4.75% Convertible Senior Notes [filed as Exhibit 4.2 to Massey's current report on Form 8-K filed May 30, 2003 and incorporated by reference]
4.3	Indenture, dated November 10, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.625% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed November 12, 2003 and incorporated by reference]
4.4	Second Supplemental Indenture, dated April 7, 2004, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, supplementing that certain Senior Indenture dated May 29, 2003, in connection with the Company's 2.25% Convertible Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed April 4, 2004 and incorporated by reference]
4.5	Indenture, dated as of December 21, 2005, Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.875% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed December 21, 2005, and incorporated by reference]

Exhibit No.	Description
10.1	Amended and Restated Credit Agreement dated as of August 15, 2006, among A. T. Massey Coal Company, Inc. and certain of its subsidiaries, as Borrowers, Massey Energy Company and certain of its subsidiaries, as Guarantors, Bank of America, N. A., as Syndication Agent, General Electric Capital Corporation, as Documentation Agent, The CIT Group/Business Credit, Inc., as Collateral Agent, UBS Securities LLC, as Arranger, UBS AG, Stamford Branch, as Administrative Agent, and UBS Loan Finance LLC, as Swingline Lender, and the lenders party thereto [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.2	Massey Energy Company 1982 Shadow Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.8 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.3	Massey Energy Company 1988 Executive Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.6 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.4	Massey Energy Company 1996 Executive Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.13 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.5	Amendment to Massey Energy 1996 Executive Stock Plan [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.6	Massey Energy Company 1997 Stock Appreciation Rights Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.9 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.7	Massey Energy Company 1999 Executive Performance Incentive Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.1 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.8	Amendment to Massey Energy Company 1999 Executive Performance Incentive Plan [contained in Item 1.01 to Massey's current report on Form 8-K filed February 24, 2006 and incorporated by reference]
10.9	Second Amendment to Massey Energy Company 1999 Executive Performance Incentive Plan [filed as Exhibit 10.5 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.10	Massey Energy Company 2006 Stock and Incentive Compensation Plan (as amended and restated effective August 15, 2006) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.11	Amendment to Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.12	Form of Non-Employee Director Initial Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.13	Form of Non-Employee Director Initial Restricted Unit Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.14	Form of Non-Employee Director Annual Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.15	Form of stock option agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.16	Form of restricted stock agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.7 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.17	Form of restricted unit agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.8 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.18	Form of cash incentive award agreement based on earnings before taxes under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.9 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.19	Form of cash incentive award agreement based on earnings before interest, taxes, deprecation and amortization under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.10 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]

Exhibit No.	Description
10.20	Massey Executive Deferred Compensation Program (as amended and restated as of January 1, 2005) [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed February 25, 2005 and incorporated by reference]
10.21	First Amendment to the Massey Executive Deferred Compensation Program [filed as Exhibit 10.10 to Massey's current report on Form 8-K filed November 17, 2005 and incorporated by reference]
10.22	A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan (as amended and restated as of January 1, 2005) [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed February 25, 2005 and incorporated by reference]
10.23	First Amendment to the A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan [filed as Exhibit 10.11 to Massey's current report on Form 8-K filed November 17, 2005 and incorporated by reference]
10.24	Second Amendment to the A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan [filed as Exhibit 10.2 to Massey's quarterly report on Form 10-Q filed August 9, 2006 and incorporated by reference]
10.25	Massey Energy Company Executive Physical Program [filed as Exhibit 10.3 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.26	Massey Executives' Supplemental Benefit Plan (as amended and restated as of January 1, 2005) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed January 5, 2006 and incorporated by reference]
10.27	Massey Executives' Supplemental Benefit Plan Agreement (effective as of January 1, 2005) between Massey and Don L. Blankenship [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed January 5, 2006 and incorporated by reference]
10.28	Massey Executives' Supplemental Benefit Plan Agreement (effective as of January 1, 2005) between Massey and H. Drexel Short, Jr. [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed January 5, 2006 and incorporated by reference]
10.29	Letter Agreement dated December 20, 2005 between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.30	Letter Agreement dated December 27, 2006, between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed January 3, 2007 and incorporated by reference]
10.31	Special Successor and Development Retention Program between Fluor Corporation and Don L. Blankenship dated as of September 1998 [filed as Exhibit 10.21 to Fluor's annual report on Form 10-K for the fiscal year ended October 31, 1998 and incorporated by this reference]
10.32	Retention and Change in Control Agreement dated November 1, 2005 Massey Energy Company and Baxter F. Phillips, Jr. [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed November 17, 2005 and incorporated by reference]
10.33	Form of Change in Control Severance Agreement for Tier 1 Participants [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.34	Form of Change in Control Severance Agreement for Tier 2 Participants [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.35	Form of Change in Control Severance Agreement for Tier 3 Participants [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.36	Change in Control Severance Agreement dated as of December 21, 2005 between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.5 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.37	Change in Control Severance Agreement dated as of December 21, 2005 between Massey Energy Company and J. Christopher Adkins [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.38	Change in Control Severance Agreement dated as of December 21, 2005 between Massey Energy Company and H. Drexel Short, Jr. [filed as Exhibit 10.7 to Massey's current report on Form 8-K filed December 22, 2005 and incorporated by reference]
10.39	Change in Control Severance Agreement dated as of December 21, 2005 between Massey Energy Company and Eric B. Tolbert [filed herewith]
10.40	Massey Energy Company 2007 Long Term Incentive Award Program as reported on Massey's current report on Form 8-K [filed November 16, 2006 and incorporated by this reference]
10.41	Massey Energy Company 2007 Bonus Program as reported on Massey's current report on Form 8-K [filed February 23, 2007 and incorporated by this reference]
10.42	Base salary amounts set for Massey's named executive officers as reported on Massey's current report on Form 8-K [filed February 24, 2006 and incorporated by this reference]

Exhibit No.	Description
10.43	Base salary amount changes for certain of Massey's named executive officers as reported on Massey's current report on Form 8-K [filed May 22, 2006 and incorporated by reference]
10.44	Base salary amount changes for certain of Massey's named executive officers as reported on Massey's current report on Form 8-K [filed November 16, 2006 and incorporated by reference]
10.45	Massey Energy Company Non-Employee Director Compensation Summary (as amended and restated effective August 16, 2006) [filed as Exhibit 10.5 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.46	Massey Energy Company Stock Plan for Non-Employee Directors (as amended and restated effective May 24, 2005) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed May 26, 2005 and incorporated by reference]
10.47	First Amendment to Massey Energy Company Stock Plan for Non-Employee Directors [filed as Exhibit 10.3 to Massey's quarterly report on Form 10-Q filed August 9, 2006 and incorporated by reference]
10.48	Second Amendment to Massey Energy Company Stock Plan for Non-Employee Directors [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.49	Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors (as amended and restated effective May 24, 2005) [filed as Exhibit 10.1 to Massey's annual report on Form 10-K for the fiscal year ended May 31, 2005 and incorporated by reference]
10.50	First Amendment to Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors [filed as Exhibit 10.4 to Massey's quarterly report on Form 10-Q filed August 9, 2006 and incorporated by reference]
10.51	Second Amendment to Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed November 16, 2006 and incorporated by reference]
10.52	Massey Energy Company Deferred Directors' Fees Program (amended and restated effective February 23, 2001) [filed as Exhibit 10.15 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.53	Distribution Agreement between Fluor Corporation and Massey Energy Company dated as of November 30, 2000 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
10.54	Tax Sharing Agreement between Fluor Corporation, Massey Energy Company and A.T. Massey Coal Company, Inc. dated as of November 30, 2000 [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
21	Massey Energy Company Subsidiaries [filed herewith]
23	Consent of Independent Auditors [filed herewith]
24	Manually signed Powers of Attorney executed by Massey directors [filed herewith]
31.1	Certification of Chief Executive Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
31.2	Certification of Chief Financial Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]

SIGNATURES

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

MASSEY ENERGY COMPANY

March 1, 2007

By: /s/ ERIC B. TOLBERT
Eric B. Tolbert,
Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
Principal Executive Officer and Director:		
/s/ DON L. BLANKENSHIP **Don L. Blankenship**	Chairman, Chief Executive Officer and President	March 1, 2007
Principal Financial Officer:		
/s/ ERIC B. TOLBERT **Eric B. Tolbert**	Vice President and Chief Financial Officer	March 1, 2007
Principal Accounting Officer:		
/s/ DAVID W. OWINGS **David W. Owings**	Controller	March 1, 2007
Other Directors:		
* **James B. Crawford**	Director	March 1, 2007
* **Robert H. Foglesong**	Director	March 1, 2007
* **E. Gordon Gee**	Director	March 1, 2007
William R. Grant	Director	
* **Bobby R. Inman**	Director	March 1, 2007
* **Daniel S. Loeb**	Director	March 1, 2007
* **Dan R. Moore**	Director	March 1, 2007
* **Martha R. Seger**	Director	March 1, 2007
* **Todd Q. Swanson**	Director	March 1, 2007

By: /s/ RICHARD R. GRINNAN March 1, 2007

Richard R. Grinnan
Attorney-in-fact

* Manually signed Powers of Attorney authorizing Baxter F. Phillips, Jr., Richard R. Grinnan and Jeffrey M. Jarosinski, and each of them, to sign the annual report on Form 10-K for the fiscal year ended December 31, 2006 and any amendments thereto as attorneys-in-fact for certain directors and officers of the registrant are included herein as Exhibits 24.

MASSEY ENERGY COMPANY

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
(In Thousands)

Description	Balance at Beginning of Period	Amounts Charged to Costs and Expenses	Deductions [1]	Other [2]	Balance at End of Period
YEAR ENDED DECEMBER 31, 2006					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 2,063	$ 12	$ (1,499)	$ -	$ 576
YEAR ENDED DECEMBER 31, 2005					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 4,240	$ (1,780)	$ (397)	$ - [3]	$ 2,063
YEAR ENDED DECEMBER 31, 2004					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 8,350	$ (3,516)	$ (594)	$ -	$ 4,240

(1) Reserves utilized, unless otherwise indicated.

(2) Reclassifications, unless otherwise indicated.

(3) In 2005, as part of the consideration for the sale of our ownership interest in Big Elk Mining Company, we received a $30 million non-interest bearing note and established an allowance of $11.5 million due to collectibility concerns. This reserve was reversed in the fourth quarter of 2005 as a result of the early repayment of the note. See Note 4 in the Notes to Consolidated Financial Statements for further discussion.

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EXHIBIT 31.1

Section 302 Certification

I, Don L. Blankenship, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2006 of Massey Energy Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2007

/s/ DON L. BLANKENSHIP

Don L. Blankenship
Chairman, Chief Executive Officer and President

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EXHIBIT 31.2

Section 302 Certification

I, Eric B. Tolbert, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2006 of Massey Energy Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2007

/s/ ERIC B. TOLBERT

Eric B. Tolbert
Vice President and Chief Financial Officer

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Shareholder information

Common Stock Information
At February 15, 2007, there were 81,068,790 shares outstanding and approximately 7,300 shareholders of record of Massey Energy's common stock.

Registrar and Transfer Agent
Wells Fargo Shareowner Services℠
Shareowner Relations Department
P.O. Box 64854
St. Paul, MN 55164-0854

For change of address, lost dividends or lost stock certificates, write or telephone:

Wells Fargo Bank, N.A.
P.O. Box 64874
St. Paul, MN 55174-0874
(800) 813-2847

Independent Auditors
Ernst & Young LLP
901 E. Cary Street
Suite 1000
Richmond, VA 23219

Annual Shareholders' Meeting
Massey Energy's annual meeting of shareholders will be held at 9:00 a.m. EDT on May 22, 2007 at:

Four Seasons Hotel
57 East 57th Street
New York, NY 10022

Stock Trading
Massey Energy's stock is traded on the New York Stock Exchange. Common stock domestic trading symbol: MEE

Duplicate Mailings
Shares owned by one person but held in different forms of the same name result in duplicate mailings of shareholder information at added expense to the Company. Such duplication can be eliminated only at the direction of the shareholder. Please notify Wells Fargo Shareowner ServicesSM in order to eliminate duplication.

Financial Information
Inquiries from shareholders and security analysts should be directed to:

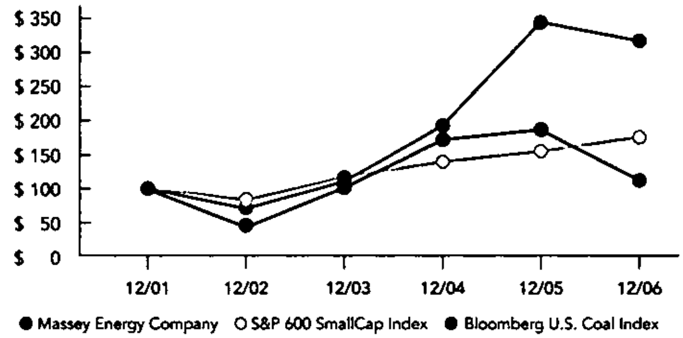
Investor Relations
Massey Energy Company
P.O. Box 26765
Richmond, VA 23261
(866) 814-6512

Website Address
www.masseyenergyco.com

Investor E-Mail
Investor@masseyenergyco.com

Ethics Hotline
(888) 424-2417

Comparison of Cumulative Total Return for the Period December 31, 2001 to December 31, 2006



	12/01	12/02	12/03	12/04	12/05	12/06
Massey Energy Company	100.0	47.7	102.8	173.5	188.8	116.6
S&P 600 SmallCap Index	100.0	85.4	118.4	145.1	156.2	179.7
Bloomberg U.S. Coal Index	100.0	75.4	118.9	193.2	347.5	321.4

The graph above compares the performance of Massey Energy's common stock with that of the S&P 600 SmallCap Index and the Bloomberg U.S. Coal Index, a published industry index. The Company is included as a composite member of the S&P 600 SmallCap Index and the Bloomberg U.S. Coal Index. The historical data provided above for both the S&P 600 SmallCap Index and the Bloomberg U.S. Coal Index comes from Bloomberg Professional Service and is based on the current composition of each respective index.

Stock Price and Dividend Information
Stock price as of December 31, 2006 was $23.23:

	2006		
Quarter	High	Low	Dividend
First	$41.53	$33.10	$ 0.04
Second	$44.34	$32.15	$ 0.04
Third	$37.05	$18.77	$ 0.04
Fourth	$28.00	$19.31	$ 0.04

Note Regarding Forward-Looking Statements
This annual report and the Form 10-K included herein contain forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995.

We caution readers that forward-looking statements and similar statements are subject to certain risks, trends and uncertainties that could cause actual cash flows, results of operations, financial condition, cost reductions, acquisitions, dispositions, financing transactions, operations, expansion, consolidation, and other events to differ materially from the expectations expressed or implied in such forward-looking statements. Any forward-looking statements are also subject to a number of assumptions regarding, among other things, future economic, competitive and market conditions. Such forward-looking statements are based on facts and conditions as they exist at the time such statements are made as well as predictions as to future facts and conditions, the accurate prediction of which may be difficult and involve the assessment of events beyond the Company's control. We disclaim any obligation to update these forward-looking statements unless required by securities law, and we caution the reader not to rely on them unduly. We have based any forward-looking statements we have made on our current expectations and assumptions about future events and circumstances that are subject to risks, uncertainties and contingencies that could cause results to differ materially from those discussed in the forward-looking statements. We refer you to a page "i" of the Form 10-K included in this annual report for a description of such items.

Additional information concerning these and other risks, uncertainties and contingencies can be found in press releases as well as Massey Energy's previous public periodic filings with the Securities and Exchange Commission. Such filings are available either publicly, under the Investor Relations page of Massey Energy's website: www.masseyenergy.com, or upon request from Massey Energy's Investor Relations Department: (866) 814-6512.

Massey Energy®

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P.O. Box 26765
Richmond, VA 23261
(804) 788-1800

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