CONSOL Energy Inc
Form 10-K
February 10, 2012

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

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
For the fiscal year ended December 31, 2011
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-14901

CONSOL Energy Inc.
(Exact name of registrant as specified in its charter)

Delaware	51-0337383
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1000 CONSOL Energy Drive
Canonsburg, PA 15317-6506
(724) 485-4000
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

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

Title of each class	Name of exchange on which registered
Common Stock ($.01 par value)	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x
Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) 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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller Reporting Company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x
The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of the common stock on the New York Stock Exchange on such date was $10,963,933,121.
The number of shares outstanding of the registrant's common stock as of January 25, 2012 is 227,093,353 shares.
DOCUMENTS INCORPORATED BY REFERENCE:
Portions of CONSOL Energy's Proxy Statement for the Annual Meeting of Shareholders to be held on May 1, 2012, are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

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FORWARD-LOOKING STATEMENTS

We are including the following cautionary statement in this Annual Report on Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of us. With the exception of historical matters, the matters discussed in this Annual Report on Form 10-K are forward-looking statements (as defined in Section 21E of the Exchange Act) that involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," or their negatives, or other expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this Annual Report on Form 10-K speak only as of the date of this Annual Report on Form 10-K; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- deterioration in global economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets cause conditions we cannot predict;
- a significant or extended decline in prices we receive for our coal and natural gas affecting our operating results and cash flows;
- our customers extending existing contracts or entering into new long-term contracts for coal;
- our reliance on major customers;
- our inability to collect payments from customers if their creditworthiness declines;
- the disruption of rail, barge, gathering, processing and transportation facilities and other systems that deliver our coal and natural gas to market;
- a loss of our competitive position because of the competitive nature of the coal and natural gas industries, or a loss of our competitive position because of overcapacity in these industries impairing our profitability;
- our inability to maintain satisfactory labor relations;
- coal users switching to other fuels in order to comply with various environmental standards related to coal combustion emissions;
- the impact of potential, as well as any adopted regulations relating to greenhouse gas emissions on the demand for coal and natural gas
- foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;
- the risks inherent in coal and natural gas operations being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, explosions, accidents and weather conditions which could impact financial results;
- decreases in the availability of, or increases in, the price of commodities or capital equipment used in our mining operations;
- decreases in the availability of, an increase in the prices charged by third party contractors or, failure of third party contractors to provide quality services to us in a timely manner could impact our profitability;
- obtaining and renewing governmental permits and approvals for our coal and gas operations;
- the effects of government regulation on the discharge into the water or air, and the disposal and clean-up of, hazardous substances and wastes generated during our coal and natural gas operations;
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our ability to find adequate water sources for our use in gas drilling, or our ability to dispose of water used or removed from strata in connection with our gas operations at a reasonable cost and within applicable environmental rules;

- the effects of stringent federal and state employee health and safety regulations, including the ability of regulators to shut down a mine or natural gas well;
- the potential for liabilities arising from environmental contamination or alleged environmental contamination in connection with our past or current coal and gas operations;

- the effects of mine closing, reclamation, gas well closing and certain other liabilities;
- uncertainties in estimating our economically recoverable coal and gas reserves;
- costs associated with perfecting title for coal or gas rights on some of our properties;
- the impacts of various asbestos litigation claims;
- the outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;
- increased exposure to employee-related long-term liabilities;
- exposure to multi-employer pension plan liabilities;
- minimum funding requirements by the Pension Protection Act of 2006 (the Pension Act) coupled with the significant investment and plan asset losses suffered during the recent economic decline has exposed us to making additional required cash contributions to fund the pension benefit plans which we sponsor and the multi-employer pension benefit plans in which we participate;
- lump sum payments made to retiring salaried employees pursuant to our defined benefit pension plan exceeding total service and interest cost in a plan year;
- acquisitions that we recently have completed or may make in the future including the accuracy of our assessment of the acquired businesses and their risks, achieving any anticipated synergies, integrating the acquisitions and unanticipated changes that could affect assumptions we may have made and divestitures we anticipate may not occur or produce anticipated proceeds;
- the terms of our existing joint ventures restrict our flexibility and actions taken by the other party in our gas joint ventures may impact our financial position;
- the anti-takeover effects of our rights plan could prevent a change of control;
- risks associated with our debt;
- replacing our natural gas reserves, which if not replaced, will cause our gas reserves and gas production to decline;
- our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- other factors discussed in this 2011 Form 10-K under “Risk Factors,” as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

PART I

ITEM 1. Business

CONSOL Energy's Business Introduction

CONSOL Energy safely and responsibly produces coal and natural gas for global energy and raw material markets, which include the electric power generation industry and the steelmaking industry. During the year ended December 31, 2011, we produced 62.6 million tons of high-British thermal unit (Btu) bituminous coal from 12 mining complexes in the United States. During this same period, our natural gas production totaled 153.5 net billion cubic feet equivalent (Bcfe) from approximately 15,000 gross natural gas wells primarily in Appalachia.

Additionally, we provide energy services, including river and dock services, terminal services, industrial supply services, water services and land resource management services.

CONSOL Energy's History

CONSOL Energy was incorporated in Delaware in 1991. Our coal operations began in 1864. CONSOL Energy's beginnings as the “Consolidation Coal Company” in Western Maryland led to growth and expansion through all major coal producing regions in the United States. CONSOL Energy entered the natural gas business in the 1980s to increase the safety and efficiency of our coal mines by capturing methane from coal seams prior to mining, which makes the mining process safer and more efficient. Over the past five years, CONSOL Energy's natural gas business has grown by over 164% to produce 153.5 net Bcfe in 2011. This business has grown from coalbed methane production in Virginia into other unconventional production, such as Marcellus Shale, in the Appalachian basin. This growth was accelerated with the 2010 asset acquisition of the Appalachian E&P business of Dominion Resources, Inc. (Dominion Acquisition). Subsequently, in August and September

2011, we announced two strategic joint ventures, one with Noble Energy, Inc. (Noble) and one with a subsidiary of Hess Corporation (Hess). These joint ventures will allow the acceleration of development of the assets acquired in the Dominion Acquisition and will focus on the development of our Marcellus and Utica asset holdings.

CONSOL Energy's Strategy

CONSOL Energy's strategy is to continue to build the Company into a large integrated energy company.

CONSOL Energy defines itself through its core values which are:
- Safety
- Compliance
- Continuous Improvement

These values are the foundation of CONSOL Energy's identity and are the basis for how management defines continued success. We believe CONSOL Energy's rich resource base, coupled with these core values allow CONSOL Energy to create value for the long-term. The electric power industry generates over two-thirds of its output by burning coal or natural gas, the two fuels we produce. We believe that the use of coal and natural gas will continue for many years as the principal fuel sources for electricity in the United States. Additionally, we believe that as worldwide economies grow, the demand for electricity from fossil fuels will grow as well, resulting in expansion of worldwide demand for our coal and natural gas.

U.S. ELECTRIC SUPPLY by ENERGY SOURCE
In percent of total

	Actuals		Preliminary	Projected
	2009	2010	2011	2015
Coal	44.4	44.8	42.9	42.3
Natural Gas	23.3	23.9	24.4	23.5
Nuclear	20.2	19.6	19.1	19.7
Conventional Hydro	6.8	6.2	7.6	7.7
Renewables	3.7	4.1	4.7	5.3
Others	1.6	1.4	1.3	1.5

Source: U.S. Energy Information Administration

Although coal is projected to lose a small percentage of market share in the U.S. electric generation market, we believe that our efficient, long-lived, well capitalized longwall mines that operate near major U.S. population centers will continue to maintain their existing market share in the U.S. thermal coal market.

We expect natural gas to become a significant contributor to the domestic electric generation mix as well as industrial segments of the U.S. economy. Also, natural gas may potentially become a significant contributor to the transportation market. Our increasing gas production will allow CONSOL Energy to participate in these markets.

The following charts show CONSOL Energy's recent growth in international coal sales and metallurgical coal sales.

CONSOL Energy's Capital Expenditure Budget

CONSOL Energy's 2012 capital expenditure budget totals $1.5 billion which is an increase from the $1.4 billion invested in 2011. The budget includes $676 million for coal, $623 million for gas, $135 million for water, and $110 million for other. The budget reflects the plan to invest in our highest rate of return projects: the organic opportunities in coal, gas, and liquid hydrocarbons. CONSOL Energy has the ability to adjust these planned investments should circumstances warrant.

The table below categorizes the 2011 actual capital expenditures and the planned 2012 capital expenditure budget.

	2011 Actual Capital Expenditures	2012 Forecasted Capital Expenditures
Coal	(in millions)	
Maintenance of Production	$243	$277
Efficiency Projects (e.g., overland belts)	$183	$146
Increases in Production (e.g., Bailey Mine Expansion)	$114	$203
Safety	$18	$50
Total Coal	$558	$676
Gas		
Marcellus	$427	$473
Utica	$3	$53
CBM	$130	$65
Other	$102	$32
Total Gas	$662	$623
Other		
Water	$49	$135
Transportation (e.g., Baltimore Terminal; barges)	$28	$30
Coal Land	$73	$55
Other	$12	$25
Total Other	$162	$245
Total Capital	$1,382	$1,544

CONSOL Energy's Operations

The following map provides the location of CONSOL Energy's coal and gas operations by region:
CONSOL Energy Operations Highlights – Coal

We have consistently ranked among the largest coal producers in the United States based upon total revenue, net income and operating cash flow. We produced 62.6 million tons of coal in 2011. Our production of 62.4 million tons of coal in 2010 accounted for approximately 6% of the total tons produced in the United States and almost 14% of the total tons produced east of the Mississippi River during 2010, the latest year for which statistics are available. CONSOL Energy holds approximately 4.5 billion tons of proved and probable coal reserves located in northern Appalachia (62%), the mid-western United States (17%), central Appalachia (15%), the western United States (4%), and in western Canada (2%) at December 31, 2011. We are one of the premier coal producers in the United States by several measures:

- We produce one of the largest amounts of coal east of the Mississippi River;
- We control one of the largest amounts of recoverable coal reserves east of the Mississippi River;
- We control the fourth largest amount of recoverable coal reserves among United States coal producers; and
- We are one of the largest United States producers of coal from underground mines.

The following table ranks the 20 largest underground mines in the United States by tons of coal produced in calendar year 2010, the latest year for which statistics are available.

MAJOR U.S. UNDERGROUND COAL MINES–2010
In millions of tons

Mine Name	Operating Company	Production
Bailey	CONSOL Energy	10.9
Enlow Fork	CONSOL Energy	10.2
McElroy	CONSOL Energy	10.1
Twenty Mile	Peabody Energy Subsidiary	7.1
Powhatan No. 6	The Ohio Valley Coal Company (Murray)	6.5
SUFCO	Arch Coal, Inc.	6.2
Century	American Energy Corp. (Murray)	6.2
Loveridge	CONSOL Energy	5.9
Cumberland	Cumberland Coal Resources (Alpha)	5.8
Warrior	Warrior Coal, LLC (Alliance)	5.8
River View	River View Coal, LLC (Alliance)	5.8
Mach No. 1	Williamson Energy, LLC (Foresight Energy)	5.8
Robinson Run	CONSOL Energy	5.5
San Juan	BHP Billiton	5.0
Emerald	Emerald Coal Resources (Alpha)	4.9
West Elk	Arch Coal, Inc.	4.8
Buchanan	CONSOL Energy	4.7
Blacksville No. 2	CONSOL Energy	4.5
Mountaineer II / Mtn. Laurel	Arch Coal, Inc.	4.4
New Era	American Energy Corp. (Murray)	4.3

Source: National Mining Association, EIA

CONSOL Energy continues to derive a substantial portion of its revenue from sales of coal to electricity generators in the United States. In 2011, sales to domestic electric generators comprised approximately 60% of coal revenue and 48% of total revenue. The largest customer represented approximately 15% of coal revenue and 12% of total revenue. The largest four customers represent approximately 40% of coal revenue and over 30% of total revenue. As natural gas revenue continues to grow, we expect the relative contribution of our largest coal customers to diminish.

CONSOL Energy Operations Highlights – Gas

CONSOL Energy is a leader in developing unconventional gas resources including the development of coalbed methane (CBM) production in the Eastern United States. Our gas operations produced 153.5 net Bcfe made up of a combination of CBM (60%), which is gas that resides in coal seams, natural gas from various shallow oil and gas sites (21%), natural gas from the Marcellus Shale (18%), and other unconventional reservoirs (1%). CONSOL Energy reported estimated net proved gas reserves of 3.5 trillion cubic feet. These reserves were made up of CBM (50%), Marcellus (25%), shallow oil and gas (21%) and other (4%). CONSOL Energy controls considerable resource positions in other unconventional shale plays including: Chattanooga, New Albany, Utica, Huron and other shales.

Our position as a gas producer is highlighted by several measures:

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We are one of the largest natural gas producers in Appalachia with approximately 15,000 total gross wells in Appalachia comprising 8% of all Appalachian wells based on 2009 U.S. Energy Information Administration data, the latest year for which statistics are available.

- We are one of the largest CBM producers, with production equal to approximately 35% of total Appalachian CBM production and 59% of Northern Appalachian production (excluding Alabama) based on 2009 U.S. Energy Information Administration data, the latest year for which statistics are available.
- We operate one of the largest gas gathering networks in Appalachia since we gather essentially all of our own production. We own and operate over 4,000 miles of gathering pipelines.
- We have been a pioneer in the exploration of unconventional gas including coalbed methane, Marcellus, Utica, Chattanooga, Huron and New Albany Shales.

In 2011, CONSOL Energy's sales of CBM gas comprised approximately 62% of gas revenue and 8% of total revenue. Sales of Marcellus gas for the same time period comprised approximately 16% of gas revenue and 2% of total revenue, and sales of shallow oil and gas comprised 21% of gas revenue and 3% of total revenue.

Coal Competition

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. CONSOL Energy competes against other large producers and hundreds of small producers in the United States and overseas. The five largest producers are estimated by the 2010 National Mining Association Survey to have produced approximately 58% (based on tonnage produced) of the total United States production in 2010. The U.S. Department of Energy reported 1,285 active coal mines in the United States in 2010, the latest year for which government statistics are available. Demand for our coal by our principal customers is affected by many factors including:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power or wind;
- environmental and government regulation;
- coal quality;
- transportation costs from the mine to the customer; and
- the reliability of fuel supply.

Continued demand for CONSOL Energy's coal and the prices that CONSOL Energy obtains are affected by demand for electricity, technological developments, environmental and governmental regulation, and the availability and price of competing coal and alternative fuel supplies. We sell coal to foreign electricity generators and to the more specialized metallurgical coal markets, both of which are significantly affected by international demand and competition.

Natural Gas Competition

The United States natural gas industry is highly competitive. CONSOL Energy competes with other large producers, thousands of small producers as well as pipeline imports from Canada and Liquefied Natural Gas (LNG) from around the globe. According to data from the Natural Gas Supply Association and the U.S. Department of Energy, the five largest producers of natural gas produced less than 21% of the total U.S. production in the third quarter of 2011. The U.S. Department of Energy reported almost 500,000 producing natural gas wells in the United States in 2009, the latest year for which government statistics are available.

CONSOL Energy's gas operations are primarily in the eastern United States. We believe that the gas market is highly fragmented and not dominated by any single producer. We believe that competition within our market is based primarily on natural gas commodity trading fundamentals and pipeline transportation availability to the various markets.

Continued demand for CONSOL Energy's natural gas and the prices that CONSOL Energy obtains are affected by demand for electricity, environmental and government regulation, technological developments and the availability and price of competing alternative fuel supplies.

Industry Segments

Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2011, 2010 and 2009 is included in Note 25–Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

DETAIL COAL OPERATIONS

Mining Complexes

The following table provides the location of CONSOL Energy's active mining complexes and the coal reserves associated with each

CONSOL ENERGY MINING COMPLEXES

Proven and Probable Assigned and Accessible Coal Reserves as of December 31, 2011 and 2010

Mine/Reserve	Location	Reserve Class	Coal Seam	Average Seam Thickness (feet)	As Received Heat Value(1) (Btu/lb) Typical	Range	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2011	Recove Reserve (tons in) Million 12/31/2
ASSIGNED–OPERATING										
Thermal Reserves										
Enlow Fork(4)	Enon, PA	Assigned	Pittsburgh	5.4	12,940	12,860 – 13,060	100%	—%	28.5	38.7
		Accessible	Pittsburgh	5.3	12,900	12,830 – 13,000	77%	23%	204.5	197.9
Bailey(4)	Enon, PA	Assigned	Pittsburgh	5.5	12,950	12,860 – 13,060	45%	55%	101.6	112.3
		Accessible	Pittsburgh	5.6	12,900	12,830 – 13,000	90%	10%	334.4	334.3
McElroy	Glen Easton, WV	Assigned	Pittsburgh	5.7	12,570	12,450 – 12,650	94%	6%	105.7	7.4
		Accessible	Pittsburgh	5.9	12,530	12,410 – 12,610	95%	5%	90.0	153.1
Shoemaker	Moundsville, WV	Assigned	Pittsburgh	5.6	12,200	11,700 – 12,300	100%	—%	68.3	44.5
		Accessible	Pittsburgh	—	—	—	—%	—%	—	27.8
Loveridge	Metz, WV	Assigned	Pittsburgh	7.5	13,000	12,850 – 13,150	76%	24%	26.4	32.0
		Accessible	Pittsburgh	7.6	13,000	12,820 – 13,100	95%	5%	13.6	13.6
Robinson Run	Shinnston, WV	Assigned	Pittsburgh	7.4	12,950	12,600 – 13,300	86%	14%	46.8	52.7
		Accessible	Pittsburgh	6.8	12,940	12,600 – 13,300	55%	45%	156.7	156.7
Blacksville #2(4)	Wana, WV	Assigned	Pittsburgh	6.7	13,020	12,800 – 13,150	81%	19%	20.3	24.7
		Accessible	Pittsburgh	6.9	13,000	12,800 – 13,100	99%	1%	16.5	16.5
Harrison Resources(3)	Cadiz, OH	Assigned	Multiple	4.5	11,570	11,350 – 11,850	100%	—%	6.7	7.1
Amvest-Fola Complex(4)	Bickmore, WV	Assigned	Multiple	4.3	12,380	12,250 – 12,550	88%	12%	92.2	53.3
Miller Creek Complex	Delbarton, WV	Assigned	Multiple	3.3	12,000	11,600 – 12,650	4%	96%	5.6	9.0

Metallurgical Reserves										
Buchanan	Mavisdale, VA	Assigned	Pocahontas 3	5.7	13,900	13,700 – 14,200	22%	78%	58.0	63.7
		Accessible	Pocahontas 3	6.0	13,930	13,650 – 14,150	10%	90%	37.0	37.0
Western Allegheny-Knob Creek(3)	Young Township, PA	Assigned	Upper Kittanning	3.2	13,050	13,000 – 13,100	100%	—%	2.3	2.4
Total Assigned Operating and Accessible									1,415.1	1,384.7

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(1) The heat value shown for assigned reserves is based on the quality of coal mined and processed during the year ended December 31, 2011. The heat value shown for accessible reserves is based on the same mining and processing methods as for the assigned reserves with adjustments made based on the variability found in exploration drill core samples. The heat values given have been adjusted to include moisture that may be added during mining or processing and for dilution by rock lying above or below the coal seam.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustments for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are reported only for those coal seams that are controlled by ownership or leases.

(3) Harrison Resources and Western Allegheny-Knob Creek are both equity affiliates in which CONSOL Energy owns a 49% interest. Reserves reported equal CONSOL Energy's 49% proportionate interest in Harrison Resources' and Western Allegheny-Knob Creek's reserves.

(4) A portion of these reserves contain metallurgical qualities and are currently being sold on the metallurgical market.

Excluded from the table above are approximately 179.3 million tons of reserves at December 31, 2011 that are assigned to projects that have not produced coal in 2011. These assigned reserves are in the Northern Appalachia (northern West Virginia and Pennsylvania), Central Appalachia (Virginia and eastern Kentucky), the Western U.S. (Utah) and Illinois Basin (Illinois) regions. These reserves are approximately 60% owned and 40% leased.

CONSOL Energy assigns coal reserves to each of our mining complexes. The amount of coal we assign to a mining complex generally is sufficient to support mining through the duration of our current mining permit. Under federal law, we must renew our mining permits every five years. All assigned reserves have their required permits or governmental approvals, or there is a high probability that these approvals will be secured.

In addition, our mining complexes may have access to additional reserves that have not yet been assigned. We refer to these reserves as accessible. Accessible reserves are proven and probable unassigned reserves that can be accessed by an existing mining complex, utilizing the existing infrastructure of the complex to mine and to process the coal in this area. Mining an accessible reserve does not require additional capital spending beyond that required to extend or to continue the normal progression of the mine, such as the sinking of airshafts or the construction of portal facilities.

Some reserves may be accessible by more than one mining complex because of the proximity of many of our mining complexes to one another. In the table above, the accessible reserves indicated for a mining complex are based on our review of current mining plans and reflect our best judgment as to which mining complex is most likely to utilize the reserve.

Assigned and unassigned coal reserves are proven and probable reserves which are either owned or leased. The leases have terms extending up to 30 years and generally provide for renewal through the anticipated life of the associated mine. These renewals are exercisable by the payment of minimum royalties. Under current mining plans, assigned reserves reported will be mined out within the period of existing leases or within the time period of probable lease renewal periods.

Coal Reserves

At December 31, 2011, CONSOL Energy had an estimated 4.5 billion tons of proven and probable reserves. Reserves are the portion of the proven and probable tonnage that meet CONSOL Energy's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels.

Reserves are defined in Securities and Exchange Commission (SEC) Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

Proven (Measured) Reserves- Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so close and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

Probable (Indicated) Reserves- 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.

Spacing of points of observation for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). Our estimates for proven reserves have the highest degree of geologic assurance. Estimates for proven reserves are based on points of observation that are equal to or less than 0.5 miles apart. Estimates for probable reserves have a moderate degree of geologic assurance and are computed from points of observation that are between 0.5 to 1.5 miles apart.

An exception is made concerning spacing of observation points with respect to our Pittsburgh coal seam reserves. Because of the well-known continuity of this seam, spacing requirements are 3,000 feet or less for proven reserves and between 3,000 and 8,000 feet for probable reserves.

CONSOL Energy's estimates of proven and probable reserves do not rely on isolated points of observation. Small pods of reserves based on a single observation point are not considered; continuity between observation points over a large area is necessary for proven or probable reserves.

Our reserve estimates are predicated on information obtained from our ongoing exploration drilling and in-mine sampling programs. Data including coal seam elevation, thickness, and, where samples are available, coal quality is entered into a computerized geological database. This information is then combined with data on ownership or control of the mineral and surface interests to determine the extent of reserves in a given area. Reserve estimates include mine recovery rates that reflect CONSOL Energy's experience in various types of underground and surface coal mines.

CONSOL Energy's reserve estimates are based on geological, engineering and market data assembled and analyzed by our staff of geologists and engineers located at individual mines, operations offices and at our principal office. The reserve estimates are reviewed and adjusted annually to reflect production of coal from reserves, analysis of new engineering and geological data, changes in property control, modification of mining methods and other factors.

Information, including the quantity and quality of reserves, coal and surface control, and other information relating to CONSOL Energy's coal reserve and land holdings, is maintained through a system of interrelated computerized databases.

Our estimate of proven and probable coal reserves has been determined by CONSOL Energy's geologists and mining engineers. Our coal reserves are periodically reviewed by an independent third party consultant. The independent consultant has reviewed the procedures used by us to prepare our internal estimates, verified the accuracy of our property reserve estimates and retabulated reserve groups according to standard classifications of reliability.

CONSOL Energy's proven and probable coal reserves fall within the range of commercially marketed coals in the United States. The marketability of coal depends on its value-in-use for a particular application, and this is affected by coal quality, such as, sulfur content, ash and heating value. Modern power plant boiler design aspects can compensate for coal quality differences that occur. Therefore, any of CONSOL Energy's coals can be marketed for the electric power generation industry. Additionally, the growth in worldwide demand for metallurgical coals allows some of our proven and probable coal reserves, currently classified as thermal coals, that possess certain qualities to be sold as metallurgical coal. The addition of this cross-over market adds additional assurance to CONSOL Energy that all of its proven and probable coal reserves are commercially marketable.

The following table sets forth our unassigned proven and probable reserves by region:

CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of December 31, 2011 and 2010

Coal Producing Region	As Received Heat Value(1) (Btu/lb)	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2011	Recoverable Reserves (tons in Millions) 12/31/2010
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)	11,400 – 13,500	72%	28%	1,448.1	1,412.2
Central Appalachia (Virginia, Southern West Virginia, Eastern Kentucky)	11,300 – 14,200	51%	49%	421.3	327.7
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,500 – 11,900	44%	56%	750.7	777.9
Western U.S. (Wyoming)	9,225	95%	5%	142.2	169.1
Western Canada (Alberta)	12,400 – 12,900	—%	100%	102.7	77.9
Total		61%	39%	2,865.0	2,764.8

(1) The heat value estimates for Northern Appalachian and Central Appalachian unassigned coal reserves include adjustments for moisture that may be added during mining or processing as well as for dilution by rock lying above or below the coal seam. The mining and processing methods currently in use are used for these estimates. The heat value estimates for the Illinois Basin, Western U.S. and Western Canada unassigned reserves are based primarily on exploration drill core data that may not include adjustments for moisture added during mining or processing or for dilution by rock lying above or below the coal seam.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness, and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustment for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam.

The following table summarizes our proven and probable reserves as of December 31, 2011 by region and type of coal or sulfur content (sulfur content per million British thermal units). Proven and probable reserves include both assigned and unassigned reserves. The table classifies bituminous coal by rank. Rank (High volatile A, B and C) of bituminous coals are classified on the basis of heat value. The table also classifies bituminous coals as medium and low volatile which are classified on the basis of fixed carbon and volatile matter. Coal is ranked by the degree of alteration it has undergone since the initial deposition of the organic material. The lowest ranked coal, lignite, has undergone less transformation than the highest ranked coal, anthracite. From the lowest to the highest rank, the coals are: lignite; sub-bituminous; bituminous and anthracite. The ranking is determined by measuring the fixed carbon to volatile matter ratio and the heat content of the coal. As rank increases, the amount of fixed carbon increases, volatile matter decreases, and heat content increases. Bituminous coals are further characterized by the amount of volatile matter present. Bituminous coals with high volatile matter content are also ranked. High volatile “A” bituminous coals have higher heat content than high volatile “C” bituminous coals. These characterizations of coal allow a user to predict the behavior of a coal when burned in a boiler to produce heat or when it is heated in the absence of oxygen to produce coke for steel production.

CONSOL Energy Proven and Probable Recoverable Coal Reserves
By Producing Region and Product (In Millions of Tons) As of December 31, 2011

	≤ 1.20 lbs. S02/MMBtu			> 1.20 ≤ 2.50 lbs. S02/MMBtu			> 2.50 lbs. S02/MMBtu				
By Region	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Total	Percent By Region
Northern Appalachia:											
Metallurgical:											
High Vol A Bituminous	—	—	—	—	—	164.6	—	—	—	164.6	3.7 %
Thermal:											
High Vol A Bituminous	—	—	—	—	—	111.3	61.8	115.5	2,250.1	2,538.7	56.9 %
Low Vol Bituminous	—	—	—	—	—	33.6	—	—	—	33.6	0.8 %
Region Total	—	—	—	—	—	309.5	61.8	115.5	2,250.1	2,736.9	61.4 %
Central Appalachia:											
Metallurgical:											
High Vol A Bituminous	—	—	32.7	—	—	29.9	—	—	1.3	63.9	1.4 %
Med Vol Bituminous	—	3.0	143.6	—	—	2.9	—	—	—	149.5	3.4 %
Low Vol Bituminous	—	—	114.1	—	—	26.3	—	—	—	140.4	3.1 %
Thermal:											
High Vol A Bituminous	34.9	80.8	2.8	44.4	126.0	2.4	9.4	15.0	—	315.7	7.1 %
Region Total	34.9	83.8	293.2	44.4	126.0	61.5	9.4	15.0	1.3	669.5	15.0 %
Midwest-Illinois Basin:											
Thermal:											
High Vol B Bituminous	—	—	—	—	65.1	—	—	444.9	—	510.0	11.4 %
High Vol C Bituminous	—	—	—	—	159.5	—	108.3	—	—	267.8	6.0 %
Region Total	—	—	—	—	224.6	—	108.3	444.9	—	777.8	17.4 %
Northern Powder River Basin:											
Thermal:											
Sub Bituminous B	—	—	142.2	—	—	—	—	—	—	142.2	3.2 %
Region Total	—	—	142.2	—	—	—	—	—	—	142.2	3.2 %
Utah-Emery Field:											
Thermal:											

High Vol B Bituminous	—	17.9	—	—	12.3	—	—	—	—	30.2	0.7 %
Region Total	—	17.9	—	—	12.3	—	—	—	—	30.2	0.7 %
Western Canada:											
Metallurgical:											
Med Vol Bituminous	30.2	72.6	—	—	—	—	—	—	—	102.8	2.3 %
Region Total	30.2	72.6	—	—	—	—	—	—	—	102.8	2.3 %
Total Company	65.1	174.3	435.4	44.4	362.9	371.0	179.5	575.4	2,251.4	4,459.4	100.0 %
Percent of Total	1.5 %	3.9 %	9.8 %	1.0 %	8.1 %	8.3 %	4.0 %	12.9 %	50.5 %	100.0 %	

The following table classifies CONSOL Energy coals by rank, projected sulfur dioxide emissions and heating value (British thermal units per pound). The table also classifies bituminous coals as high, medium and low volatile which is based on fixed carbon and volatile matter.

CONSOL Energy Proven and Probable Recoverable Coal Reserves
By Product (In Millions of Tons) As of December 31, 2011

	≤ 1.20 lbs. S02/MMBtu			> 1.20 ≤ 2.50 lbs. S02/MMBtu			> 2.50 lbs. S02/MMBtu				
By Region	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Total	Percent By Product
Metallurgical:											
High Vol A Bituminous	—	—	32.7	—	—	194.5	—	—	1.3	228.5	5.1 %
Med Vol Bituminous	30.2	75.6	143.6	—	—	2.9	—	—	—	252.3	5.7 %
Low Vol Bituminous	—	—	114.1	—	—	26.3	—	—	—	140.4	3.1 %
Total Metallurgical	30.2	75.6	290.4	—	—	223.7	—	—	1.3	621.2	13.9 %
Thermal:											
High Vol A Bituminous	34.9	80.8	2.8	44.4	126.0	113.7	71.2	130.5	2,250.1	2,854.4	64.0 %
High Vol B Bituminous	—	17.9	—	—	77.4	—	—	444.9	—	540.2	12.1 %
High Vol C Bituminous	—	—	—	—	159.5	—	108.3	—	—	267.8	6.0 %
Low Vol Bituminous	—	—	—	—	—	33.6	—	—	—	33.6	0.8 %
Sub Bituminous B	—	—	142.2	—	—	—	—	—	—	142.2	3.2 %
Total Thermal	34.9	98.7	145.0	44.4	362.9	147.3	179.5	575.4	2,250.1	3,838.2	86.1 %
Total	65.1	174.3	435.4	44.4	362.9	371.0	179.5	575.4	2,251.4	4,459.4	100.0 %
Percent of Total	1.5 %	3.9 %	9.8 %	1.0 %	8.1 %	8.3 %	4.0 %	12.9 %	50.5 %	100.0 %	

The following table categorizes the relative Btu values (low, medium and high) for each of CONSOL Energy's producing regions in Btu's per pound of coal.

Region	Low	Medium	High
Northern, Central Appalachia and Canada	< 12,500	12,500 – 13,000	> 13,000
Midwest Appalachia	< 11,600	11,600 – 12,000	> 12,000
Northern Powder River Basin	< 8,400	8,400 – 8,800	> 8,800
Colorado and Utah	< 11,000	11,000 – 12,000	> 12,000

Title to coal properties that we lease or purchase and the boundaries of these properties are verified by law firms retained by us at the time we lease or acquire the properties. Consistent with industry practice, abstracts and title reports are reviewed and updated approximately five years prior to planned development or mining of the property. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine reserves could be adversely affected.

The following table sets forth, with respect to properties that we lease to other coal operators, the total royalty tonnage, acreage leased and the amount of income (net of related expenses) we received from royalty payments for the years ended December 31, 2011, 2010 and 2009.

Year	Total Royalty Tonnage (in thousands)	Total Coal Acreage Leased	Total Royalty Income (in thousands)
2011	8,488	289,833	$17,998
2010	8,606	226,524	$14,073
2009	11,403	232,181	$16,448

Royalty tonnage leased to third parties is not included in the amounts of produced tons that we report. Proven and probable reserves do not include reserves attributable to properties that we lease to third parties.

Compliance Compared to Non-Compliance Coal

Coals are sometimes characterized as compliance or non-compliance coal. The term "compliance coal," as it is commonly used in the coal industry, refers to compliance only with former national sulfur dioxide emissions standards and indicates that when burned, the coal will produce emissions that will not exceed 1.2 pounds of sulfur dioxide per million British thermal units (1.2lb S02/MM Btu). A coal considered a compliance coal for meeting this former sulfur dioxide standard may not meet an emission standard for a different pollutant such as mercury, and may not even meet newer sulfur emission standards for all power plants. Clean air regulations that further restrict sulfur dioxide emissions will likely significantly reduce the amount of coal that can be used without post-combustion emission control technologies. Currently, a compliance coal will meet the power plant emission standard of 1.2 lb S02/MM Btu of fuel consumed. At December 31, 2011, approximately 0.7 billion tons, or 15%, of our coal reserves met that standard as a compliance coal. It is likely that, within several years, no coal will be "compliant" because federal regulations will require emissions-control technology to be used regardless of the coal's sulfur content. In many cases, our customers have responded to ever-tightening emissions requirements by retrofitting flue gas desulfurization systems (scrubbers) to existing power plants. Because these systems remove sulfur dioxide before it is emitted into the atmosphere, those customers are less concerned about the sulfur content of our coal.

As a result of a 1998 court decision forcing the establishment of mercury emissions standards for power plants, the Environmental Protection Agency (EPA) was required to promulgate a regulatory program for controlling mercury. CONSOL Energy coals have mercury contents typical for their rank and location (approximately 0.07-0.15 parts mercury on a dry coal basis). Since CONSOL Energy coals have high heating values, they have lower mercury contents on a weight per energy basis (typically measured in pounds per trillion Btu) than lower rank coals at a given mercury concentration. Eastern bituminous coals also tend to produce a greater proportion of flue gas mercury in the ionic or oxidized form (which is more easily captured by scrubbers installed for sulfur control) than sub-bituminous coal, including coals produced in the Powder River Basin. Both high rank and low rank coals are also amenable to other methods of controlling mercury emissions, such as by powder activated carbon injection. The EPA's proposed Clean Air Mercury Rule was vacated by a federal court ruling. The EPA is currently developing new regulations to control multiple hazardous air pollutants, including mercury, from coal-fired plants, the so-called MACT Rule, which is expected to be finalized in 2014. Some states have already adopted a control program for mercury emissions from coal-fired power plants.

Production

In the year ended December 31, 2011, 94% of CONSOL Energy's production came from underground mines and 6% from surface mines. Where the geology is favorable and reserves are sufficient, CONSOL Energy employs longwall mining systems in our underground mines. For the year ended December 31, 2011, 91% of our production came from mines equipped with longwall mining systems. Underground longwall systems are highly mechanized, capital intensive operations. Mines using longwall systems have a low variable cost structure compared with other types of mines and can achieve high productivity levels compared with those of other underground mining methods. Because CONSOL Energy has substantial reserves readily suitable to these operations, CONSOL Energy believes that these longwall mines can increase capacity at a low incremental cost.

The following table shows the production, in millions of tons, for CONSOL Energy's mines in the years ended December 31, 2011, 2010 and 2009, the location of each mine, the type of mine, the type of equipment used at each mine, method of transportation and the year each mine was established or acquired by us.

Mine	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2011	2010	2009	Year Established or Acquired
Thermal								
McElroy	Glen Easton, WV	U	LW/CM	CB B	9.3	10.1	9.9	1968
Bailey	Enon, PA	U	LW/CM	R R/B	8.8	9.8	10.4	1984
Enlow Fork	Enon, PA	U	LW/CM	R R/B	8.3	9.1	11.1	1990
Robinson Run	Shinnston, WV	U	LW/CM	R CB	5.6	5.5	5.6	1966
Loveridge	Metz, WV	U	LW/CM	R T	5.5	5.9	6.0	1956
Shoemaker(2)	Moundsville, WV	U	LW/CM	B	5.1	3.9	0.4	1966
Blacksville #2(1)	Wana, WV	U	LW/CM	R R/B T	4.2	4.5	3.8	1970
Miller Creek Complex(3)	Delbarton, WV	U/S	CM/S/L	R T	2.8	3.0	3.2	2004
AMVEST–Fola Complex(1)(3)	Bickmore, WV	U/S	A/S/L/CM	R T	2.1	1.9	3.0	2007
Harrison Resources(3)(4)	Cadiz, OH	S	S/L	R T	0.4	0.5	0.4	2007
Emery(1)	Emery Co., UT	U/S	CM	T	—	1.0	1.2	1945
Buchanan–Thermal(1)	Mavisdale, VA	U	LW/CM	R	—	0.2	0.7	1983
Jones Fork Complex(1)(3)(5)	Mousie, KY	U/S	CM/S/L	R T	—	0.1	1.1	1992
Mine 84(1)(6)	Eighty Four, PA	U	LW/CM	R R/B T	—	—	0.5	1998
High Volatile Metallurgical								
Bailey–Met	Enon, PA	U	LW/CM	R R/B	2.1	1.2	—	1984
Enlow Fork–Met	Enon, PA	U	LW/CM	R R/B	1.8	1.1	—	1990
Robinson Run–Met	Shinnston, WV	U	LW/CM	R CB	0.4	—	—	1966
Blacksville #2(1)–Met	Wana, WV	U	LW/CM	R R/B T	0.1	—	—	1970
Western Allegheny–Knob Creek(3)(4)	Young Township, PA	U	CM	R T	0.1	0.1	—	2010
Loveridge–Met	Metz, WV	U	LW/CM	R T	0.1	—	—	1956
AMVEST–Fola Complex(1)(3)–Met	Bickmore, WV	U/S	A/S/L/CM	R T	0.1	—	—	2007
AMVEST–Terry Eagle Complex(1)(3)–Met	Jodie, WV	U/S	CM/A/S/L	R T	0.1	—	—	2007
Low Volatile Metallurgical								
Buchanan(1)	Mavisdale, VA	U	LW/CM	R T	5.7	4.5	2.1	1983
Total					62.6	62.4	59.4	

A – Auger
S – Surface
U – Underground
LW – Longwall
CM – Continuous Miner
S/L – Stripping Shovel and Front End Loaders
R – Rail

B	–	Barge
R/B	–	Rail to Barge
T	–	Truck
CB	–	Conveyor Belt
(1)	–	Mine was idled for part of the year(s) presented due to market conditions.
(2)	–	Mine was idled throughout most of 2009 due to converting from track haulage, to more efficient belt haulage to remove coal from the mine.
(3)	–	Harrison Resources, Miller Creek Complex, AMVEST–Fola Complex, AMVEST–Terry Eagle Complex, Jones Fork Complex and Western Allegheny–Knob Creek include facilities operated by independent contractors.
(4)	–	Production amounts represent CONSOL Energy's 49% ownership interest.
(5)	–	Complex was sold in March 2010.
(6)	–	Mine 84 was permanently idled in 2011.

Coal Capital Projects

CONSOL Energy anticipates investing $277 million for maintenance-of-production projects and $203 million to projects such as the BMX Mine (see below for BMX description.) Also, $146 million is planned for efficiency improvements such as the overland belt at Enlow Fork Mine and $50 million is planned for health and safety items.

In 2011, capital projects included the continued development of the BMX Mine. This project is expected to add 5 million tons a year of high-quality Pittsburgh seam coal, which will be sold in either the high-volatile metallurgical or thermal markets. An extension of Bailey Mine began in 2009 and production from the first longwall panel is expected to start in early 2014. The total cost of the project is expected to be approximately $662 million of which approximately $132 million was incurred in 2011. As of December 31, 2011, total project-to-date expenditures were approximately $175 million. Included within the scope of this project are certain surface facility upgrades at the Bailey Preparation Plant which are necessary in order for the plant to process the additional coal from the BMX Mine. These upgrades include the construction of several new raw and clean coal silos, expansion of existing railroad facilities, and installation of additional raw coal material handling systems.

In 2011, capital projects included the continued development of the Amonate Complex. This project is expected to add 400 - 600 thousand tons a year of mid-volatile met coal. The total cost of the project is expected to be approximately $53 million of which approximately $22 million was incurred in 2011. Production from the Amonate Complex is expccted to begin in 2012.

Construction of a new slope and overland belt at the Enlow Fork Mine in Pennsylvania began in 2010 and is expected to be completed by the end of 2013. Overland belt projects are expected to enhance safety, improve productivity, increase production and reduce costs. Modern conveyor systems typically provide high availability rates, thereby allowing mining equipment to produce at higher levels. Overland belts do not require the daily maintenance of the mine roof that underground haulage systems require allowing manpower to be reduced or redeployed to more productive work. Mine safety is expected to be enhanced by overland belts because older underground belt areas will be sealed. The total cost of the project is expected to be approximately $207 million of which approximately $28 million was incurred in 2011. As of December 31, 2011, total project-to-date expenditures were approximately $38 million.

Also, in accordance with a consent decree with the U.S Environmental Protection Agency and the West Virginia Environmental Protection Agency, CONSOL Energy began construction of an advance water processing system (RO) in Northern West Virginia in 2011. The RO will provide a treatment system for the mine water generated from the Robinson Run, Loveridge, and Blacksville #2 Mines to be in compliance with the existing National Pollution Discharge Elimination System (NPDES) permits. Construction was started in April 2011 and final commissioning of the RO system is expected to be complete by the end of May 2013. Expenditures related to the Northern West Virginia plant of $48.0 million were incurred in 2011 and total costs related to the construction of this plant and related facilities is expected to be approximately $200 million.

	2011 Actual Capital Expenditures	2012 Forecasted Capital Expenditures
Coal	(in millions)	
Maintenance of Production	$243	$277
Efficiency Projects (e.g., overland belts)	$183	$146
Increases in Production (e.g., BMX)	$114	$203
Safety	$18	$50
Total Coal	$558	$676

Coal Marketing and Sales

Our sales of bituminous coal were at average sales price per ton sold as follows:

	Years Ended December 31,		
	2011	2010	2009
Average Sales Price Per Ton Sold– Thermal Coal	$58.87	$53.76	$56.64
Average Sales Price Per Ton Sold– High Volatile Met Coal	$78.06	$72.89	$—
Average Sales Price Per Ton Sold– Low Volatile Met Coal	$191.81	$146.32	$107.72
Average Sales Price Per Ton Sold– Total Company	$72.25	$61.33	$58.70

We sell coal produced by our mining complexes and additional coal that is purchased by us for resale from other producers. We maintain United States sales offices in Charlotte, Philadelphia and Pittsburgh. In addition, we sell coal through agents and to brokers and unaffiliated trading companies.

A breakdown of total coal sales, including our portion of equity affiliates, are as follows:

	Tons Sold	Percent of Total	
Thermal	53.4	83	%
High Volatile Metallurgical	4.8	8	%
Low Volatile Metallurgical	5.6	9	%
Total tons sold	63.8	100	%

Approximately 75% of our 2011 coal sales were made to U. S. electric generators,18% of our 2011 coal sales were priced on export markets and 7% of our coal sales were made to other domestic customers. We had approximately 105 customers in 2011. During 2011, one customer individually accounted for more than 10% of total revenue, and the top four coal customers accounted for more than 30% of our total revenues.

Coal Contracts

We sell coal to an established customer base through opportunities as a result of strong business relationships, or through a formalized bidding process. Contract volumes range from a single shipment to multi-year agreements for millions of tons of coal. The average contract term is between one to three years. However, several multi-year agreements have terms ranging from five to twenty years. As a normal course of business, efforts are made to renew or extend contracts scheduled to expire. Although there are no guarantees, we generally have been successful in renewing or extending contracts in the past. For the year ended December 31, 2011, over 84% of all the coal we produced was sold under contracts with terms of one year or more.

The following table sets forth as of January 26, 2012, CONSOL Energy's estimated production and sales for 2012 through 2014.
COAL DIVISION GUIDANCE
(Tons in millions)

	1Q 2012	2012	2013	2014
Estimated Coal Production	15.5-15.9	59.5-61.5	60.5-62.5	64.5-66.5
Estimated Low-Vol Met Sales	1.0	4.5-5.0	4.5-5.0	4.5-5.0
Tonnage - Firm	1.0	1.9	0.1	—
Average Price - Sold (firm)	$189.68	$185.66	$93.48	N/A
Price - Estimated (for open tonnage)	$115-$145	$120-$150	N/A	N/A
Estimated High-Vol Met Sales	1.0	5.0	5.0	5.5-6.0
Tonnage - Firm	0.7	1.9	0.2	0.1
Average Price - Sold (firm)	$84.47	$82.10	$90.27	$105.58
Price - Estimated (for open tonnage)	$68-$75	$68-$80	N/A	N/A
Estimated Thermal Sales	13.2	49.6-51.1	50.4-51.9	53.9-54.9
Tonnage - Firm	12.5	49.7	23.5	14.4
Average Price - Sold (firm)	$61.64	$62.77	$62.77	$64.01
Price - Estimated (for open tonnage)	$58-$65	$58-$65	N/A	N/A

Note: N/A means not available or not forecasted. In the thermal sales category, the firm tonnage does not include 4.7 million collared tons in 2013, with a ceiling of $59.78 per ton and a floor of $51.63 per ton or 7.0 million collared tons in 2014, with a ceiling of $60.13 per ton and a floor of $46.76 per ton. Total estimated coal sales for 2012, 2013 and 2014 include 0.4, 0.6 and 0.6 million tons, respectively, from Amonate. The Amonate tons are not included in the category breakdowns. None of the Amonate tons have been sold.

Coal pricing for contracts with terms of one year or less is generally fixed. Coal pricing for multiple-year agreements generally provides the opportunity to periodically adjust the contract prices through pricing mechanisms consisting of one or more of the following:

- Fixed price contracts with pre-established prices; or
- Periodically negotiated prices that reflect market conditions at the time; or
- Price restricted to an agreed-upon percentage increase or decrease; or
- Base-price-plus-escalation methods which allow for periodic price adjustments based on inflation indices.

The volume of coal to be delivered is specified in each of our coal contracts. Although the volume to be delivered under the coal contracts is stipulated, the parties may vary the timing of the deliveries within specified limits.

Coal contracts typically contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events. Force majeure events include, but are not limited to, labor disputes and unexpected significant geological conditions. Depending on the language of the contract, some contracts may terminate upon continuance of an event of force majeure that extends for a period greater than three to twelve months.

Distribution

Coal is transported from CONSOL Energy's mining complexes to customers by means of railroad cars, river barges, trucks, conveyor belts or a combination of these means of transportation. We employ transportation specialists who negotiate freight and equipment agreements with various transportation suppliers, including railroads, barge lines, terminal operators, ocean vessel brokers and trucking companies for certain customers. Most customers negotiate their own freight contracts.

At December 31, 2011 we operated 22 towboats, 5 harbor boats and a fleet of approximately 625 barges that serve customers along the Ohio, Allegheny, Kanawha and Monongahela Rivers. The barge operation allows us to control delivery schedules and has served as temporary floating storage for coal when land storage is unavailable.

DETAIL GAS OPERATIONS

Our Gas operations are located throughout Appalachia. While CBM remains our largest share of production much of our future growth will likely come from the development of our Marcellus Shale play and the exploration of our Utica Shale play.

Coalbed Methane (CBM)

We have the rights to extract CBM in Virginia from approximately 359,000 net CBM acres, which cover a portion of our coal reserves in Central Appalachia. We produce gas primarily from the Pocahontas #3 seam which is the main coal seam mined by our Buchanan Mine. This seam is generally found at depths of 2,000 feet and generally ranges from 3 to 6 feet thick. The gas content of this seam is typically between 400 and 600 cubic feet of gas per ton of coal in place. In addition, there are as many as 50 thinner seams present in the several hundred feet above the main Pocahontas #3 seam. Collectively, this series of coal seams represents a total thickness ranging from 15 to 40 feet. We have access to core hole data that allows us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

We also have the right to extract CBM in northwestern West Virginia and southwestern Pennsylvania from approximately 859,000 net CBM acres, which contain most of our recoverable coal reserves in Northern Appalachia. We produce gas primarily from the Pittsburgh #8 coal seam. This seam is generally found at depths of less than 1,000 feet and generally ranges from 4 to 7 feet thick. The gas content of this seam is typically between 100 and 250 cubic feet of gas per ton of coal in place. There are additional coal seams above and below the Pittsburgh #8 seam. Collectively, this series of coal seams represents a total thickness ranging from 10 to 30 feet. We have access to information that allows us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

In central Pennsylvania we have the right to extract CBM from approximately 263,000 net CBM acres, which contain most of our recoverable coal reserves as well as significant leases from other coal owners. In addition, we control 810,000 net CBM acres in Illinois, Kentucky, Indiana, and Tennessee. We also have the right to extract CBM on 139,000 net acres in the San Juan Basin, 92,000 net acres in eastern Ohio and central West Virginia, and 20,000 net acres in the Powder River Basin.

Marcellus Shale

We have the rights to extract natural gas in Pennsylvania, West Virginia and New York from approximately 361,000 net Marcellus acres at December 31, 2011. In September 2011, CONSOL Energy entered into a joint venture with Noble Energy regarding our Marcellus Shale oil and gas assets and properties in West Virginia and Pennsylvania. The joint venture holds approximately 628,000 net Marcellus Shale acres in those states as well as the producing Marcellus Shale Wells which we had owned. We hold a 50% interest in the joint venture. We also hold a 50% interest in a related gathering company to which we contributed our existing Marcellus Shale gathering assets. Joint operations are conducted in accordance with a joint development agreement.

CONSOL Energy's Marcellus wells are primarily horizontal wells with 2,500 to 5,000 feet of lateral length. The longer lateral lengths allow for proportionately higher gas production from a single well compared to shorter length lateral wells.

CONSOL Energy continues to develop its Marcellus assets.

Utica Shale

CONSOL Energy also controls approximately 114,000 net acres of Utica Shale potential in southeastern Ohio, southwestern Pennsylvania, and northern West Virginia at December 31, 2011. Additionally, CONSOL Energy controls a large number of acres that contain the rights to the Utica Shale but are disclosed in other plays due to the

Utica Shale not being the primary drilling target as of December 31, 2011. The thickness of the Utica Shale in this area ranges from 200 to 450 feet. Further delineation of the Ohio acreage potential exploration play is planned for 2012.

To facilitate the delineation in Ohio, CONSOL Energy entered into a joint venture with Hess Ohio Developments, LLC (Hess) in the fourth quarter of 2011. The Hess joint venture owns approximately 200,000 net acres of Utica Shale rights in Ohio. We hold a 50% interest in the joint venture. Joint operations are conducted in accordance with a joint development agreement.

Shallow Oil and Gas

The shallow oil and gas acreage position of CONSOL Energy is approximately 518,000 net acres mainly in West Virginia, Pennsylvania, Virginia, New York, San Juan Basin and Powder River Basin at December 31, 2011. The majority of our shallow oil and gas leasehold position is held by production and all of it is extensively overlain by existing third party gas gathering and transmission infrastructure. The shallow oil and gas assets provide multiple synergies with our CBM and unconventional shale operations, and the held by production nature of the shallow oil and gas properties affords CONSOL Energy considerable flexibility to choose when to exploit those and other gas assets including shale assets.

Other Gas

We control approximately 346,000 net acres of rights to gas in the New Albany shale in Kentucky, Illinois, and Indiana. The New Albany shale is a formation containing gaseous hydrocarbons, and our acreage position has thickness of 50-300 feet at an average depth of 2,500-4,000 feet.

The Chattanooga Shale in Tennessee is a Devonian-age shale found at a depth of approximately 3,500 feet. The shale thickness is between 40-80 feet, and CONSOL Energy has found it to be rich in total organic content. CONSOL Energy has 249,000 net acres of Chattanooga Shale. This largely contiguous acreage is composed of only a small number of leases, a rarity in Appalachia. CONSOL Energy is the operator of all of its Chattanooga Shale wells.

We have 457,000 net acres of Huron shale potential in Kentucky, West Virgina, and Virginia; a portion of this acreage has tight sands potential.

Summary of Properties as of December 31, 2011

	CBM Segment	Shallow Oil and Gas Segment	Marcellus Segment	Other Gas Segment	Total
Estimated Net Proved Reserves (million cubic feet equivalent)	1,729,571	740,165	881,881	128,410	3,480,027
Percent Developed	68 %	91 %	27 %	29 %	61 %
Net Producing Wells (including gob wells)	4,231	8,351	58	85	12,725
Net Proved Developed Acres	247,192	166,255	1,690	6,737	421,874
Net Proved Undeveloped Acres	72,819	34,363	5,101	11,993	124,276
Net Unproved Acres(1)	2,221,532	316,902	354,347	1,147,817	4,040,598
Total Net Acres(2)	2,541,543	517,520	361,138	1,166,547	4,586,748

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable.

(2) Acreage amounts are shown under the target strata CONSOL Energy expects to produce, although the reported acre may include rights to multiple gas seams (CBM, Shallow Oil and Gas, Marcellus, etc.). We have reviewed our drilling plans, our acreage rights and used our best judgment to reflect the acre in the strata we expect to produce. As more information is obtained or circumstances change, the acreage classification may change.

Producing Wells and Acreage

Most of our development wells and proved acreage is located in Virginia, West Virginia and Pennsylvania. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments or other term commitments are satisfied. The following table sets forth, at December 31, 2011, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Wells (including gob wells)	14,743	12,725
Proved Developed Acreage	507,949	421,874
Proved Undeveloped Acreage	146,479	124,276
Unproven Acreage	5,035,749	4,040,598
Total Acreage	5,690,177	4,586,748

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable.

Development Wells (Net)

During the years ended December 31, 2011, 2010 and 2009 we drilled 254.9, 317.0 and 247.0 net development wells, respectively. Gob wells and wells drilled by other operators that we participate in are excluded. There were no dry development wells in 2011, one dry development well in 2010, and one dry developmental well in 2009. As of December 31, 2011, forty-seven net developmental wells are still in process. The following table illustrates the net wells drilled by well classification type:

	For the Year Ended December 31,		
	2011	2010	2009
CBM segment	221.4	184.0	228.0
Shallow Oil and Gas segment	4.0	107.0	5.0
Marcellus segment	17.5	24.0	14.0
Other Gas segment	12.0	2.0	—
Total Development Wells	254.9	317.0	247.0

For the year ended December 31, 2011, the Marcellus Segment includes 15 gross developmental wells drilled prior to September 30, 2011. A 50% interest in these wells was subsequently sold to Noble on September 30, 2011. Net developmental wells of 2.5 were drilled after September 30, 2011 under the joint venture agreement and are reflected in the table above at the applicable ownership percentage.

Exploratory Wells (Net)

During the years ended December 31, 2011, 2010 and 2009, we drilled in the aggregate 69.5, 38 and 18 net exploratory wells, respectively. As of December 31, 2011, 2.5 net exploratory wells are still in process. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2011			2010			2009		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
CBM segment	—	—	—	—	—	—	2.0	—	—
Shallow Oil and Gas segment	12.0	1.0	1.0	2.0	—	3.0	2.0	—	2.0
Marcellus segment	47.5	1.0	—	—	—	—	2.0	1.0	—
Other Gas segment	5.5	—	1.5	18.0	2.0	13.0	5.0	—	4.0
Total	65.0	2.0	2.5	20.0	2.0	16.0	11.0	1.0	6.0

For the year ended December 31, 2011, the Marcellus Segment includes 41 gross exploratory wells drilled prior to September 30, 2011. A 50% interest in these wells was sold to Noble on September 30, 2011. Net exploratory wells of 7.5 were drilled after September 30, 2011 under the joint venture agreement and are reflected in the table above at the applicable ownership percentage.

Reserves

The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of royalty interest. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and proved undeveloped reserves are defined by the Securities and Exchange Commission (SEC). CONSOL Energy has not filed reserve estimates with any federal agency.

	Net Reserves (Million cubic feet equivalent) as of December 31,		
	2011	2010	2009
Proved developed reserves	2,135,805	1,931,272	1,040,257
Proved undeveloped reserves	1,344,222	1,800,325	871,134
Total proved developed and undeveloped reserves(a)	3,480,027	3,731,597	1,911,391

(a) For additional information on our reserves, see “Other Supplemental Information–Supplemental Gas Data (unaudited) to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Discounted Future Net Cash Flows

The following table shows our estimated future net cash flows and total standardized measure of discounted future net cash flows at 10%:

	Discounted Future Net Cash Flows (Dollars in millions)		
	2011	2010	2009
Future net cash flows	$4,877	$5,474	$2,391
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$2,861	$2,780	$1,480
Total standardized measure of after tax discounted future net cash flows	$1,747	$1,661	$894

(1) We calculate our present value at 10% (PV-10) in accordance with the following table. Management believes that the presentation of the non-Generally Accepted Accounting Principle (GAAP) financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes estimated to be paid, the use of a pre-tax measure is valuable when comparing companies based on reserves. PV-10 is not a measure of the financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of the most directly comparable GAAP measure-after-tax discounted future net cash flows.

Reconciliation of PV-10 to Standardized Measure

	As of December 31,		
	2011	2010	2009
	(Dollars in millions)		
Future cash inflows	$14,804	$16,724	$7,975
Future production costs	(5,263)	(5,176)	(3,123)
Future development costs (including abandonments)	(1,675)	(2,720)	(996)
Future net cash flows (pre-tax)	7,866	8,828	3,856
10% discount factor	(5,006)	(6,048)	(2,376)
PV-10 (Non-GAAP measure)	2,860	2,780	1,480
Undiscounted income taxes	(2,989)	(3,354)	(1,465)
10% discount factor	1,876	2,235	879
Discounted income taxes	(1,113)	(1,119)	(586)
Standardized GAAP measure	$1,747	$1,661	$894

Gas Production

The following table sets forth net sales volumes produced for the periods indicated:

	For the Year Ended December 31,		
	2011	2010	2009
	(in million cubic feet)		
CBM segment	92,360	91,351	86,944
Shallow Oil and Gas segment	32,168	24,646	1,663
Marcellus segment	26,873	10,408	4,950
Other Gas segment	2,103	1,470	858
Total Produced	153,504	127,875	94,415

Gas Capital Projects

CONSOL Energy plans to spend $473 million on developing its extensive Marcellus Shale assets in 2012. Included in this is drilling capital of $333 million. The budget anticipates that the CONSOL/Noble Energy joint venture will drill 99 (gross) horizontal Marcellus Shale wells, including 39 (gross) wells in the liquids-rich area of the play. CONSOL also expects to invest $77 million in related gathering and compression and $63 million on other related items.

In the CONSOL/Hess joint venture in the Utica Shale, CONSOL Energy expects to invest $53 million in 2012. Most of that will be drilling capital for CONSOL Energy's share of up to 22 gross wells. Most of the Utica drilling is expected to occur in either the liquids-rich area or the oil window of the play.

As a result, the total drilling in the liquids-rich/oil window is expected to be the 39 (gross) wells in the Marcellus Shale, plus the 22 (gross) wells in the Utica Shale, for a total of 61 (gross) wells out of the 121 (gross) wells, or 50%, expected to be drilled in the two plays.

The CBM program will be scaled back in 2012 with the expected drilling of only 86 wells. Total capital for the 2012 CBM program is estimated to be $65 million.

Across all of the gas plays, the $623 million includes $433 million of drilling capital, $108 million of gathering and compression capital, $21 million for production equipment, $23 million for water, $23 million for land and $15 million for other.

As a result of the expected gas investment, CONSOL Energy projects its 2012 gas production to be 160 Bcfe net to CONSOL Energy. This will be an increase of nearly 12%, off of pro forma 2011 production of 142.9 Bcf, adjusted for the partial year impact of Marcellus assets sold to Noble Energy and Antero Resources.

The company expects 2013 gas/liquids production target of between 190 - 210 Bcfe, which will be achieved largely from the ramp-up in drilling in 2012.

The table below summarizes the 2011 actual expenditures made for gas and the forecasted expenditures for 2012.

	2011 Actual Capital Expenditures	2012 Forecasted Capital Expenditures
Gas	(in millions)	
Marcellus Shale	$427	$473
Utica Shale	$3	$53
CBM	$130	$65
Other	$102	$32
Total Gas	$662	$623

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Gas Sales

Average Sales Price and Average Lifting Cost

The following table sets forth the total average sales price and the total average lifting cost for all of our gas production for the periods indicated, including intersegment transactions. Total lifting cost is the cost of raising gas to the gathering system and does not include depreciation, depletion or amortization. See Part II Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K for a breakdown by segment.

	For the Year Ended December 31,		
	2011	2010	2009
Average Gas Sales Price Before Effects of Financial Settlements (per thousand cubic feet)	$4.27	$4.53	$4.15
Average Effects of Financial Settlements (per thousand cubic feet)	$0.63	$1.30	$2.53
Average Gas Sales Price Including Effects of Financial Settlements (per thousand cubic feet)	$4.90	$5.83	$6.68
Average Lifting Costs excluding ad valorem and severance taxes (per thousand cubic feet)	$0.68	$0.50	$0.48

We enter into physical gas sales transactions with various counterparties for terms varying in length. Reserves and production estimates are believed to be sufficient to satisfy these obligations. In the past, other than interstate pipeline outages related to maintenance issues or a weather related force majeure event, we have not failed to deliver quantities required under contract. We also enter into various gas swap transactions that qualify as financial cash flow hedges. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 84.0 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2011 at an average price of $5.21 per thousand cubic feet. These financial hedges represented approximately 52.1 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2010 at an average price of $7.66 per thousand cubic feet. As of December 31, 2011, we expect these transactions will cover approximately 76.9 billion cubic feet of our estimated 2012 production at an average price of $5.25 per thousand cubic feet, 50.8 billion cubic feet of our estimated 2013 production at an average price of $5.06 per thousand cubic feet, 44.0 billion cubic feet of our estimated 2014 production at an average price of $5.20 per thousand cubic feet and 3.8 billion cubic feet of our estimated 2015 production at an average price of $3.97 per thousand cubic feet.

We have purchased firm transportation capacity on various interstate pipelines to ensure gas production flows to market. As of December 31, 2011, we have secured firm transportation capacity to cover more than our 2012, 2013 and 2014 hedged production.

The hedging strategy and information regarding derivative instruments used are outlined in Part II Item 7A Qualitative and Quantitative Disclosures About Market Risk and in Note 23 – Derivative Instruments in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

Midstream Gas Services

CONSOL Energy has traditionally designed, built and operated natural gas gathering systems to move gas from the wellhead to interstate pipelines or other local sales points. In addition, CONSOL Energy acquired extensive gathering assets in the Dominion Acquisition in 2010. CONSOL Energy now owns or operates approximately 4,000 miles of gas gathering pipelines as well as 230,000 horsepower of compression, of which, approximately 80% is wholly owned with the balance being leased. Along with this compression capacity, CONSOL Energy owns and operates a number of gas processing facilities. This infrastructure is capable of delivering 200 billion cubic feet per year of pipeline quality gas.

On September 30, 2011, in connection with the Noble joint venture for Marcellus wells and leaseholdings, CONE Gathering, LLC was formed. CONSOL Energy and Noble each own 50% of CONE Gathering. CONE Gathering was formed to develop, operate and own both Noble's and CONSOL Energy's Marcellus gathering system needs.

Upon formation of CONE Gathering, CONSOL Energy contributed its then existing Marcellus Shale gathering assets to CONE Gathering. We believe that the network of right-of-ways, vast surface holdings and experience in building and operating gathering systems in the Appalachian basin will give CONE Gathering a tremendous advantage in building the midstream assets required to develop the joint venture's Marcellus position.

CONSOL Energy has had the advantage of having gas production from CBM, which can be lower Btu than pipeline specification, as well as higher Btu Marcellus production which can complement each other by reducing and in some cases eliminating the need for the costly processing of CBM. In addition, the lower Btu CBM production offers an opportunity to blend ethane back into the gas stream when pricing or capacity for ethane markets dictate. This will allow CONSOL Energy more flexibility in bringing Marcellus on-line at qualities that meet interstate pipeline specifications.

Other Operations

CONSOL Energy provides other services both to our own operations and to others. These include land services, industrial supply services, terminal services (including break bulk, general cargo and warehouse services), river and dock services and water services.

Non-Core Mineral Assets and Surface Properties

CONSOL Energy owns significant coal and gas assets that are not in our short or medium term development plans. We continually explore the monetization of these non-core assets by means of sale, lease, contribution to joint ventures, or a combination of the foregoing in order to bring the value of these assets forward for the benefit of our shareholders. We also control a significant amount of surface acreage. This surface acreage is valuable to us in the development of the gathering system for our Marcellus Shale and Utica Shale production. We also derive value from this surface control by granting rights of way or development rights to third parties when we are able to derive appropriate value for our shareholders.

Industrial Supply Services

Fairmont Supply Company, a CONSOL Energy subsidiary, is a general-line distributor of mining, drilling, and industrial supplies in the United States. Fairmont Supply has 37 customer service centers nationwide. Fairmont Supply also provides integrated supply procurement and management services. Integrated supply procurement is a materials management strategy that utilizes a single, full-line distribution to minimize total cost in the maintenance, repair and operating supply chain.

Fairmont Supply provides mine and drilling supplies to CONSOL Energy's mining and gas operations. Approximately 45% of Fairmont Supply's sales in 2011 were made to CONSOL Energy's coal and gas divisions.

Terminal Services

In 2011, approximately 12.6 million tons of coal were shipped through CONSOL Energy's subsidiary, CNX Marine Terminal Inc.'s, exporting terminal in the Port of Baltimore. Approximately 48% of the tonnage shipped was produced by CONSOL Energy coal mines. The terminal can either store coal or load coal directly into vessels from rail cars. It is also one of the few terminals in the United States served by two railroads, Norfolk Southern Corporation and CSX Transportation Inc.

River and Dock Services

CONSOL Energy's river operations, located in Monessen, Pennsylvania, transport coal from our mines, coal from other mines and non-coal commodities from river loadout facilities located primarily along the Monongahela and Ohio Rivers in northern West Virginia and southwestern Pennsylvania. Products are delivered to customers along the Monongahela, Ohio, Kanawha and Allegheny rivers. At December 31, 2011, we operated 22 towboats, 5 harbor boats and approximately 625 barges. In 2011, our river vessels transported a total of 19.1 million tons of coal and other commodities, including 6.2 million tons of coal produced by CONSOL Energy mines.

CONSOL Energy provides dock services for our mines as well as for third parties at our Alicia Dock, located on the Monongahela River in Fayette County, Pennsylvania. CONSOL Energy transfers coal from rail cars to barges for customers that receive coal on the river system.

Water Services

CNX Water Assets LLC, a CONSOL Energy subsidiary, is acquiring and developing existing sources of water used to support our coal and gas operations. CNX Water Assets LLC, operates an advanced waste water treatment plant in support of coal operations as well as fresh water reservoirs. CNX Water Assets objective is to develop and maximize the value of existing water assets, which will be used to provide water for drilling and hydraulic fracturing in support of gas operations and meeting the needs of mining operations. CNX Water also has contracts to provide water to third parties for industrial use from various water sources owned by CONSOL Energy.

Employee and Labor Relations

At December 31, 2011, CONSOL Energy had 9,157 employees, approximately 32% of whom were represented by the United Mine Workers of America (UMWA). In 2011, the Bituminous Coal Operators Association (BCOA) and the United Mine Workers of America (UMWA) reached a new collective bargaining agreement which will run from July 1, 2011 to December 31, 2016. The National Bituminous Coal Wage Agreement of 2011 (2011 NBCWA) covers approximately 2,900 employees of CONSOL Energy subsidiaries. The 2011 NBCWA is the successor agreement to the 2007 NBCWA that was set to expire on December 31, 2011. Key elements of the new agreement include the following items:

a. A wage increase of $1.00 per hour effective July 1, 2011, and an additional $1.00 per hour increase each January 1st throughout the contract term.
b. Contributions to the 1974 Pension Plan, a multi-employer plan, will continue at the current rate of $5.50 per hour throughout the contract term. New inexperienced miners hired after December 31, 2011 will not participate in the 1974 Pension Plan, but will receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014-2016) to the UMWA Cash Deferred Savings Plan (CDSP), which is a 401(k) Plan. UMWA represented employees with over 20 years of credited service under the 1974 Pension Plan will receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014-2016) to the CDSP beginning January 1, 2012. Also beginning January 1, 2012, UMWA represented employees will have the right to elect to opt-out of future participation in the 1974 Pension Plan and upon such election, will receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014 - 2016) to the CDSP.
c. A $1.50 per hour contribution starting January 1, 2012 to a new defined contribution plan to provide retiree bonus payments to eligible retirees in 2014, 2015 and 2016.
d. An increased contribution from $0.50 per hour to $1.10 per hour effective January 1, 2012 to the 1993 Benefit Plan, which is a defined contribution plan providing health benefits to certain retirees.
e. Various other changes related to absenteeism, contributions to various UMWA benefit funds, eligibility for various vacation days and sick days.

Laws and Regulations

The mining and gas industries are subject to regulation by federal, state and local authorities on matters such as the discharge of materials into the environment, permitting and other licensing requirements, reclamation and restoration of properties after mining or gas operations are completed, management of materials generated by mining and gas operations, pipeline compression and transmission of natural gas and liquids, surface subsidence from underground mining, water discharge effluent limits, water appropriation, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations on land use, storage of petroleum products and substances that are regarded as hazardous under applicable laws, management of electrical equipment containing polychlorinated biphenyls (PCBs), legislatively mandated benefits for current and retired coal miners, and employee health and safety. In addition, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for CONSOL Energy's coal and gas products. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on CONSOL Energy's mining or gas operations or our customers' ability to use coal or gas and may require CONSOL Energy or our customers to change their operations significantly or incur substantial costs.

Numerous governmental permits and approvals are required for mining and gas operations. Regulations provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a stockholder with a 10% or greater interest in the entity is affiliated with or is in a position to control another entity that has outstanding permit violations. Thus, all mining operations of CONSOL Energy entities must be maintained in compliance to avoid delay in issuance of necessary mining permits. CONSOL Energy is, or may be, required to prepare and present to federal, state or local authorities data and/or analysis pertaining to the effect or impact that any proposed exploration for or production of coal or gas may have upon the environment, the public and employee health and safety. Permits we need may include requirements that may be subject to future restrictive standards or interpreted in a manner which restricts our ability to conduct our mining and gas operations or to do so profitably. Future legislation and administrative regulations may increasingly emphasize the protection of the environment and employee health and safety. As a consequence, the activities of CONSOL Energy may be more closely regulated. Such legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in equipment and operating costs to CONSOL Energy and delays, interruptions or a termination of operations, the extent of which cannot be predicted.

Compliance with these laws has substantially increased the cost of mining and gas production for all domestic coal and gas producers. We post surety performance bonds or letters of credit pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, often including the cost of treating mine water discharge. We also post performance bonds or letters of credit pursuant to state oil and gas laws and regulations to guarantee reclamation of gas well sites and plugging of gas wells. We endeavor to conduct our mining and gas operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements against a backdrop of variable geologic and seasonal conditions, permit exceedances and violations during mining and gas production can and do occur. CONSOL Energy made capital expenditures for environmental control facilities of approximately $53.1 million, $39.9 million and $50.4 million in the years ended December 31, 2011, 2010 and 2009, respectively. The capital expenditures for environmental control facilities in 2009 were primarily related to starting construction of an advanced water processing system at the Buchanan Mine. Construction of this facility was completed in 2010. In accordance with a consent decree with the U.S. Environmental Protection Agency and the West Virginia Environmental Protection Agency, CONSOL Energy began construction of an advance water processing system in Northern West Virginia in 2011. Construction is expected to be complete in 2013. Expenditures related to the Northern West Virginia plant of $48.0 million were incurred in 2011 and total costs related to the construction of this plant and related facilities is expected to be approximately $200 million. CONSOL Energy expects to have capital expenditures of $132.2 million in 2012 for environmental control facilities.

Mine Health and Safety Laws

Legislative and regulatory changes have required us to purchase additional safety equipment, construct stronger seals to isolate mined out areas, and engage in additional training. We have also experienced more aggressive inspection protocols resulting in the issuance of more citations and with new regulations the amount of civil penalties have increased.

The actions taken thus far by federal and state governments include requiring:

- the caching of additional supplies of self-contained self rescuer (SCSR) devices underground;
- the purchase and installation of electronic communication and personal tracking devices underground;
- the placement of refuge chambers, which are structures designed to provide refuge for groups of miners during a mine emergency when evacuation from the mine is not possible, which will provide breathable air for 96 hours;
- the replacement of existing seals in worked-out areas of mines with stronger seals;
- the purchase of new fire resistant conveyor belting underground;
- additional training and testing that creates the need to hire additional employees; and
- more stringent rock dusting requirements.

On August 31, 2011, MSHA published a proposed rule, which if adopted, would require proximity protection for miners. The proposed rule would require certain underground mining equipment to be equipped with devices that will shut the equipment down if a person is too close to the equipment to avoid injuries where individuals could be caught between equipment and blocks of unmined coal. MSHA is also considering new rules to reduce the permissible concentration of respirable dust in underground coal mines. This rule, if adopted, would reduce the current standard of two milligrams per cubic meter of air to some lower amount.

Occupational Safety and Health Act

Our gas operations are subject to regulation under the federal Occupational Safety and Health Act (OSHA) and comparable state laws in some states, all of which regulate health and safety of employees at our gas operations. Also, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced by our gas operations and that this information be provided to employees, state and local governments and the public.

Black Lung Legislation

Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to:

- current and former coal miners totally disabled from black lung disease;
- certain survivors of a miner who dies from black lung disease or pneumoconiosis; and
- a trust fund for the payment of benefits and medical expenses to claimants whose last mine employment was before January 1, 1970, where no responsible coal mine operator has been identified for claims (where a miner's last coal employment was after December 31, 1969), or where the responsible coal mine operator has defaulted on the payment of such benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

The Patient Protection and Affordable Care Act (PPACA), which was implemented in 2010, made two changes to the Federal Black Lung Benefits Act. First, it provided changes to the legal criteria used to assess and award claims by creating a legal

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presumption that miners are entitled to benefits if they have worked at least 15 years in underground coal mines, or in similar conditions, and suffer from a totally disabling lung disease. To rebut this presumption, a coal company would have to prove that a miner did not have black lung or that the disease was not caused by the miner's work. Second, it changed the law so black lung benefits will continue to be paid to dependent survivors when the miner passes away, regardless of the cause of the miner's death.

In addition to the federal legislation, we are also liable under various state statutes for black lung claims.

Retiree Health Benefits Legislation

The Coal Industry Retiree Health Benefit Act of 1992 (the Act) established the Combined Benefit Fund (the Combined Fund). The Combined Fund provides medical and death benefits for all beneficiaries including orphan retirees of the former United Mine Workers of America (UMWA) Benefit Trusts who were actually receiving benefits as of July 20, 1992. The Act also created a second benefit fund for UMWA retirees, the 1992 Benefit Plan. The 1992 Benefit Plan principally provides medical and death benefits to orphan UMWA-represented members eligible for retirement on February 1, 1993, and who actually retired between July 20, 1992 and September 30, 1994. The Act provides for the assignment of beneficiaries to former signatory employers or related companies and the allocation of responsibility for unassigned beneficiaries (referred to as orphans) to the assigned operators. The task of calculating the annual per beneficiary premium that assigned operators are obligated to pay to the Combined Fund is the responsibility of the Commissioner of Social Security.

The UMWA 1993 Benefit Plan is a defined contribution plan that was created as the result of negotiations for the National Bituminous Coal Wage Agreement (NBCWA) of 1993. This plan provides health care benefits to orphan UMWA retirees who are not eligible to participate in the Combined Fund, the 1992 Benefit Fund, or whose last employer signed the 1993 NBCWA or a later NBCWA, and who subsequently goes out of business.

The Act requires some of our signatory subsidiaries to make premium payments to the Combined Fund and to the 1992 Benefit Plan for the cost of our retirees and orphan retirees in those plans. In addition, the NBCWA of 2011 requires our signatory subsidiaries to make specified payments to the 1993 Benefit Plan through 2016. The Tax Relief and Health Care Act of 2006 (the 2006 Act) provides additional federal funding for these orphan costs by authorizing general fund revenues and expanding transfers of interest from the Abandoned Mine Land (AML) trust fund. The additional federal funding, depending upon its magnitude and the amount of orphan benefits payable, should cover the orphan premium payments due under the Combined Fund as well as the orphan premium payments due under the 1992 Benefit Plan. Federal contributions were 100% in 2011 and are expected to continue to be 100% after 2011. In addition, federal contributions cover the costs for those orphan retirees as of December 31, 2006 under the 1993 Benefit Plan. Under the 2006 Act, these general fund contributions to the Combined Fund, the 1992 Benefit Plan and the 1993 Benefit Plan and certain AML payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. These federal contributions do not apply to our subsidiaries' assigned retired miners, and therefore our subsidiaries will continue to make premium payments for our assigned retired miners who receive benefits from the Combined Fund, the 1992 Benefit Plan and for certain beneficiaries of the 1993 Benefit Plan. In addition, our subsidiaries remain responsible for making orphan premium payments to the Combined Fund and 1992 Benefit Plan to the extent that the federal contributions are not sufficient to cover the benefits.

Pension Protection Act

The Pension Protection Act of 2006 (the Pension Act) has simplified and transformed rules governing the funding of defined benefit plans, accelerated funding obligations of employers, made permanent certain provisions of the Economic Growth and Tax Relief Reconciliation Act of 2001 (EGTRRA), made permanent the diversification rights and investment education provisions for plan participants and encourages automatic enrollment in defined contribution 401(k) plans. In general, most provisions of the Pension Act of 2006 are in effect for plan years beginning on or after December 31, 2008. Plans generally are required to set a funding target of 100% of the present value of accrued benefits and sponsors are required to amortize unfunded liabilities over a seven year period. The Pension Act includes a funding target of 100% after 2010. Plans with a funded ratio of less than 80%, or less than 70% using special assumptions, will be deemed to be "at risk" and will be subject to additional funding requirements. The 2011 plan year funding ratio of CONSOL Energy's salary retirement plan was 100%. The funding ratio is subject to year over year volatility and Internal Revenue Service's calculation guidelines.

Environmental Laws

CONSOL Energy is subject to various federal environmental laws, including:

- the Surface Mining Control and Reclamation Act of 1977,
- the Clean Air Act,
- the Clean Water Act,
- the Endangered Species Act,
- the Resource Conservation and Recovery Act,
- the Comprehensive Environmental Response, Compensation and Liability Act,
- the Toxic Substances Control Act, and
- the Emergency Planning and Community Right to Know Act,

as administered and enforced by the United States Environmental Protection Agency (EPA) and/or authorized federal or state agencies, as well as state laws of similar scope, and other state environmental and conservation laws in each state in which CONSOL Energy operates.

These environmental laws require reporting, permitting and/or approval of many aspects of coal mining and gas operations. Both federal and state inspectors regularly visit mines and other facilities to ensure compliance. CONSOL Energy has ongoing compliance and permitting programs designed to ensure compliance with such environmental laws.

Given the retroactive nature of certain environmental laws, CONSOL Energy has incurred, and may in the future incur liabilities in connection with properties and facilities currently or previously owned or operated. These liabilities may be increased to include sites to which CONSOL Energy or our subsidiaries sent waste materials.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act (SMCRA) establishes minimum national operational, reclamation and closure standards for all surface mines as well as most aspects of deep mines. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the Office of Surface Mining (OSM) or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the appropriate state regulatory authority. States that operate federally approved state programs may impose standards which are more stringent than the requirements of SMCRA and OSM's regulations and in many instances have done so. All states in which CONSOL Energy's active mining operations are located have achieved primary jurisdiction for enforcement of SMCRA through approved state programs.

SMCRA permit provisions include requirements for coal exploration; baseline environmental data collection and analysis; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; refuse disposal plans; surface drainage control; mine drainage and mine discharge control and treatment; and site reclamation. All states also impose an obligation on surface mining operations to restore or replace domestic, agricultural or industrial water supplies and on underground mine operations to restore or replace drinking, domestic or residential water supplies adversely affected by such operations. In addition, SMCRA imposes a reclamation fee on all current mining operations, the proceeds of which are deposited in the Abandoned Mine Reclamation Fund (AML Fund), which is used to restore unreclaimed and abandoned mine lands mined before 1977. The current per ton fee is $0.315 per ton for surface mined coal and $0.135 per ton for underground mined coal. From October 1, 2012 through September 30, 2021, the fees will be $0.28 per ton for surface mined coal and $0.12 per ton for underground mined coal.

OSM is currently considering modifications to the existing stream buffer zone regulation, which amendments are referred to as the Stream Protection Rule. An advanced notice of proposed rulemaking (ANPR) was published in November 2009. Based on the ANPR, the proposed rule would apply to surface mining as well as underground mining activities that may impact streams. Although it is too early to predict what the impacts of the proposed amendments will be, all of the alternatives identified in the ANPR could result in loss of access to significant amounts of coal and/or significant increases in reclamation costs. In Pennsylvania, where CONSOL Energy operates two longwall mines, approximately $29.4 million, $21.8 million and $30.3 million of expenses were incurred during the years ended December 31, 2011, 2010 and 2009, respectively, to mitigate and repair impacts on streams from subsidence. With respect to subsidence impacts to streams, the regulatory requirement to minimize impacts to the hydrologic balance could cause CONSOL Energy to change mine plans, to incur significant costs, and potentially even shut down mines in order to meet compliance requirements. We currently estimate expenses related to subsidence of streams in Pennsylvania will be approximately $34.7 million for the year ended December 31, 2012.

Clean Air Act and Related Regulations

The federal Clean Air Act and similar state laws and regulations which regulate emissions into the air, affect coal mining, coal handling and processing, and gas production and processing operations primarily through permitting and/or emissions control requirements.

The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of the coal fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide, a greenhouse gas, is also emitted when coal is burned. Environmental regulations governing emissions from coal-fired electric generating plants could affect demand for coal as a fuel source and affect the volume of our sales.

In 2011, the EPA promulgated or finalized several rulemakings impacting coal generating facilities. These include the Cross-State Air Pollution Rule to regulate sulfur dioxide (SO_2), nitrogen dioxide (NO_x) and fine particulate matter; and the Utility Maximum Achievable Control Technology (Utility MACT) rule which sets new mercury and air toxic standards and includes more stringent new source performance standards (NSPS) for particulate matter (PM), SO_2 and $NO_{X.}$

In addition, the EPA is proposing to establish NSPS for Green House Gas (GHG) emissions from new electric generating units and proposed regulations to establish GHG emission limits for new and modified electric generating units. The EPA anticipates that a notice of proposed rulemaking (NOPR) will be published in the Federal Register in early 2012. Such regulations could significantly increase the cost of generation of electricity at coal fired facilities and could make competing forms of electricity generation more competitive.

The Clean Air Act and comparable state laws restrict the emission of air pollutants from compressor stations and other equipment and facilities used in our gas operations. We are required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions. In August 2011, the EPA published proposed revisions to the NSPS and proposed revisions to the national emission standards for hazardous air pollutants (NESHAPS) for the Oil and Natural Gas Sector. The EPA intends to issue the final revisions in early 2012. In September 2009, the EPA finalized the Mandatory Reporting of Greenhouse Gas Rule. The current version of this rule requires reporting of emissions from coal mines and gas wells and associated facilities for 2011 emissions.

Clean Water Act

The federal Clean Water Act (CWA) and corresponding state laws affect coal and gas operations by regulating discharges into surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The Clean Water Act and corresponding state laws include requirements for: improvement of designated "impaired waters" (not meeting state water quality standards) through the use of effluent limitations; anti-degradation regulations which protect state designated "high quality/exceptional use" streams by restricting or prohibiting discharges; requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides, selenium and dissolved solids; for minimizing impacts and compensating for unavoidable impacts resulting from discharges of fill materials to regulated streams and wetlands; and the requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. In addition, the Spill Prevention, Control and Countermeasure (SPCC) requirements of the CWA apply to all CONSOL Energy operations that use or produce fluids, including brine and oil, and require that plans be in place to address any spills and that secondary containment be installed around all tanks. These requirements may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

In order to obtain a permit for surface coal mining activities, including valley fills associated with steep slope mining, an operator must obtain a permit for the discharge of fill material from the Army Corps of Engineers (the COE) pursuant to Section 404 of the Clean Water Act and must obtain a discharge permit from the state regulatory authority under the state counterpart to Section 402 of the Clean Water Act authorizing the issuance of national pollutant discharge elimination permits or NPDES permits. Beginning in early 2009, the EPA took a number of initiatives that have resulted in delays and obstruction of the issuance of such permits for surface mining operation in the states of Kentucky, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia (designated as "Appalachian Surface Coal Mining"). Increased oversight of delegated state programmatic authority, coupled with individual permit review and additional requirements imposed by the EPA, has resulted in delays in the review and issuance of permits for surface coal mining operations, including applications for surface facilities for underground mines, such as applications for coal refuse disposal areas. Thus far, CONSOL Energy subsidiaries have been able to continue operating their existing mines. However, such delays and obstructions in the permitting process may cause CONSOL Energy to incur additional costs that could adversely affect our operating results, financial condition and cash flows.

Pursuant to a Congressional requirement in the EPA's 2010 budget appropriation, the EPA must conduct a comprehensive study of the potential adverse impact that hydraulic fracturing may have on water quality and public health. Hydraulic fracturing is a way of producing gas from tight rock formations such as the Barnett and Marcellus shales. The EPA initiated the study in early January 2011 and plans to make the initial study results available by late 2012, with a final report to Congress soon thereafter. The EPA has also announced plans to conduct a review of water produced in conjunction with the production of Coal Bed Methane (CBM) to determine whether its disposal should be further regulated.

Endangered Species Act

The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered and threatened species may cause us to modify mining plans, gas well pad siting or pipeline right of ways, or develop and implement species-specific protection and enhancement plans to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA. Based on the species that have been identified and the current application of applicable laws and regulations, we do not believe that there are any species protected under the ESA or state laws that would materially and adversely affect our ability to mine coal or produce gas from our properties.

Comprehensive Environmental Response, Compensation and Liability Act (Superfund)

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) and similar state laws create liabilities for the investigation and remediation of releases of hazardous substances into the environment and for damages to natural resources. We could incur liability under CERCLA relative to our coal or gas operations. Our current and former coal mining operations incur, and will continue to incur, expenditures associated with the investigation and remediation of facilities and environmental conditions, including underground storage tanks, solid and hazardous waste disposal and other matters under Superfund and similar state environmental laws. We also must comply with reporting requirements under the Emergency Planning and Community Right-to-Know Act and the Toxic Substances Control Act.

From time to time, we have been the subject of administrative proceedings, litigation and investigations relating to sites that have released hazardous substances. We have been in the past and currently are named as a potentially responsible party at Superfund sites. We may become involved in future proceedings, litigation or investigations and incur liabilities that could be materially adverse to us.

Resource Conservation and Recovery Act

The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect coal mining and gas operations by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed are subject to corrective action orders issued by the EPA which could adversely affect our results, financial condition and cash flows.

The EPA is currently reconsidering the regulation of coal combustion waste, with a decision expected in late 2012. Depending on the outcome of that decision, demand for coal fired electricity generation could be adversely impacted.

Federal Regulation of the Sale and Transportation of Gas

Various aspects of our gas operations are regulated by agencies of the federal government. The Federal Energy Regulatory Commission regulates the transportation and sale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. While "first sales" by producers of natural gas, and all sales of condensate and natural gas liquids can be made currently at uncontrolled market prices, Congress could reenact price controls in the future.

Regulations and orders set forth by the Federal Energy Regulatory Commission also impact our gas business to a certain degree. Although the Federal Energy Regulatory Commission does not directly regulate our gas production activities, the Federal Energy Regulatory Commission has stated that it intends for certain of its orders to foster increased competition within all phases of the natural gas industry. Additionally, the Federal Energy Regulatory Commission continues to review its transportation regulations, including whether to allocate all short-term capacity on the basis of competitive auctions and whether changes to its long-term transportation policies may also be appropriate to avoid a market bias toward short-term

contracts. Additional Federal Energy Regulatory Commission orders have been adopted based on this review with the goal of increasing competition for natural gas markets and transportation.
The Federal Energy Regulatory Commission has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the Federal Energy Regulatory Commission does not have jurisdiction over services provided by these facilities, then such facilities and services may be subject to regulation by state authorities in accordance with state law. In addition, the Federal Energy Regulatory Commission's approval of transfers of previously-regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to Federal Energy Regulatory Commission regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future.

We own certain natural gas pipeline facilities that we believe meet the traditional tests which the Federal Energy Regulatory Commission has used to establish a pipeline's status as a gatherer not subject to the Federal Energy Regulatory Commission jurisdiction

Additional proposals and proceedings that might affect the gas industry may be pending before Congress, the Federal Energy Regulatory Commission, the Minerals Management Service, state commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a significantly adverse effect upon the capital expenditures, earnings or competitive position of CONSOL Energy or its subsidiaries. No material portion of our business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

State Regulation of Gas Operations

Our gas operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the siting and construction of well pads and roads, drilling of wells, bonding requirements, protection of ground water and surface water resources and protection of drinking water supplies, the method of drilling and casing wells, the surface use and restoration of well sites, gas flaring, the plugging and abandoning of wells, the disposal of fluids used in connection with operations, and gas operations producing coalbed methane in relation to active mining. A number of states have either enacted new laws or may be considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although we do not believe that they would be affected by such regulation any differently than other natural gas producers or gatherers. However, these regulatory burdens may affect profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Ownership of Mineral Rights

CONSOL Energy acquires ownership or leasehold rights to coal and gas properties prior to conducting operations on those properties. As is customary in the coal and gas industries, we have generally conducted only a summary review of the title to coal and gas rights that are not in our development plans, but which we believe we control. This summary review is conducted at the time of acquisition or as part of a review of our land records to determine control of mineral rights. Given CONSOL Energy's long history as a coal producer, we believe we have a well-developed ownership position relating to our coal control; however, our ownership of oil and gas rights, particularly those rights that we acquired in connection with our historic coal operations, is less developed. As we continue to review our land records and confirm title in anticipation of development, we expect that adjustments to our ownership position (either increases or decreases) will be required.

Prior to the commencement of development operations on coal or gas properties, we conduct a thorough title examination and perform curative work with respect to significant defects. We are typically responsible for the cost of curing any title defects. We generally will not commence operations on a property until we have cured any material title defects on such property. We have completed title work on substantially all of our coal and gas producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the industry.

A recent decision by the intermediate appellate court in Pennsylvania in a case captioned Butler v. Powers (Pa. Superior

Ct., No. 1795 MDA 2010) did not change the law of Pennsylvania with respect to the ownership of Marcellus Shale gas rights, but in remanding the case to the trial court for further proceedings, it called into question the applicability of a long-standing presumption known as the Dunham Rule to gas in the Marcellus Shale. The Dunham Rule is a presumption that a reservation or conveyance of minerals does not reserve or convey oil and gas absent an express reference to oil and gas. We believe that the Pennsylvania courts will ultimately confirm that the Dunham Rule applies to Marcellus Shale gas; however, if the Pennsylvania courts were to hold otherwise, we could be exposed to lawsuits challenging our rights to Marcellus Shale gas in some of our Pennsylvania properties where our rights derive from persons who did not also own the mineral rights and we may have to incur substantial additional costs to perfect our gas title in those Pennsylvania properties.

The ownership of CBM is an issue under the laws of some states, including states in which we operate. The following summary sets forth an analysis of provisions of Pennsylvania, Virginia and West Virginia law relating to the ownership of CBM. These summaries do not purport to be complete and are qualified in their entirety by reference to the provisions of applicable law and rights and the laws relating to traditional natural gas resources may differ materially from the rights related to CBM. These summaries are based on current law as of the date of this Annual Report on Form 10-K.

Pennsylvania

In Pennsylvania, CBM that remains inside the coal seam is generally the property of the owner of that coal seam where the gas is located. CBM can be sold in place or leased by the coal owner to another party such as a producer who then would have the right to extract the gas from the coal seam under the terms of the agreement with the coal owner. Once the gas migrates from the coal into other strata, the coal owner no longer has clear title to that migrated gas. As a result, in certain circumstances in Pennsylvania (e.g., in a gob or mine void), we may be required to obtain other property interests (beyond ownership or leasehold interest in the coal rights or CBM) in order to extract gas that is no longer located in the coal seam. We believe that under Pennsylvania law, a coal lessee under a lease to exhaustion would be in the same position as the coal owner with respect to ownership of the CBM.

Virginia

The Virginia Supreme Court has stated that the grant of coal rights only does not include rights to CBM, absent evidence to the contrary. The situation may be different if there is any expression in the severance deed indicating that more than mere coal is conveyed. Virginia courts have also found that the owner of the CBM does not have the right to fracture the coal in order to retrieve the CBM and that the coal operator has the right to ventilate the CBM in the course of mining.

In Virginia, we believe that we control the relevant property rights in order to capture gas from our producing properties. When necessary, we utilize an administrative procedure established by Virginia law that permits the development of CBM by an operator in those instances where the owner of the CBM has not leased it to the operator or in situations where there are conflicting claims of ownership of the CBM within a drilling unit. The general practice is to “force pool” both the coal owner and the gas owner by filing an application with and obtaining an order from the Virginia Gas and Oil Board that permits the development of the CBM in the drilling unit notwithstanding lack of control of the CBM or conflicting claims of ownership. Any royalties otherwise payable to conflicting claimants are paid into escrow and the burden then is upon the conflicting claimants to establish ownership by court action. The Virginia Gas and Oil Board does not make ownership decisions. Several lawsuits are pending in Virginia state courts and several purported class action lawsuits are pending in the Federal District Court for the Western District of Virginia in Abingdon, Virginia, including two lawsuits to which a CONSOL Energy subsidiary is named as a defendant, which seek, among other things, a court order establishing ownership of the CBM relating to the royalties currently held in escrow.

West Virginia

The ownership of CBM is largely an open question in West Virginia. The West Virginia Supreme Court has held that under a conventional oil and gas lease executed prior to the inception of widespread public knowledge regarding CBM operations, the oil and gas lessee did not acquire the right to produce CBM. The West Virginia courts have not further clarified who owns CBM in West Virginia.

West Virginia has enacted the Coalbed Methane Wells and Units Act (the West Virginia Act), regulating the commercial recovery and marketing of CBM. Although the West Virginia Act does not specify who owns, or has the right to exploit, CBM in West Virginia and instead refers ownership disputes to judicial resolution, it contains provisions similar to Virginia's force pooling law described above. Under the pooling provisions of the West Virginia Act, an applicant who proposes to drill can prosecute an administrative proceeding with the West Virginia Coalbed Methane Review Board to obtain authority to produce

CBM from pooled acreage. Owners and claimants of CBM interests who have not consented to the drilling are afforded certain elective forms of participation in the drilling (e.g., royalty or owner), but their consent is not required to obtain a pooling order authorizing the production of CBM by the operator within the boundaries of the drilling unit. The West Virginia Act also provides that, where title to subsurface minerals has been severed in such a way that title to coal and title to natural gas are vested in different persons, the operator of a CBM well permitted, drilled and completed under color of title to the CBM from either the coal seam owner or the natural gas owner has an affirmative defense to an action for willful trespass relating to the drilling and commercial production of CBM from that well.

Other States

We have rights to extract CBM where we have coal rights in other states. The ownership of CBM in the Illinois Basin and certain other western basins may be uncertain or could belong to other holders of real estate interests and we may need to acquire additional rights from other holders of real estate interests to extract and produce CBM in these other states

Available Information

CONSOL Energy maintains a website on the World Wide Web at www.consolenergy.com. CONSOL Energy makes available, free of charge, on this website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the 1934 Act), as soon as reasonably practicable after such reports are available, electronically filed with, or furnished to the SEC, and are also available at the SEC's website www.sec.gov.

Executive Officers of the Registrant

Incorporated by reference into this Part I is the information set forth in Part III, Item 10 under the caption “Directors and Executive Officers of CONSOL Energy” (included herein pursuant to Item 401 (b) of Regulation S-K).

ITEM 1A. Risk Factors

Investment in our securities is subject to various risks, including risks and uncertainties inherent in our business. The following sets forth factors related to our business, operations, financial position or future financial performance or cash flows which could cause an investment in our securities to decline and result in a loss.
Deterioration in the global economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets, may have adverse impacts on our business and financial condition that we currently cannot predict.
Economic conditions in a number of industries in which our customers operate, such as electric power generation and steel making, substantially deteriorated in recent years and reduced the demand for natural gas and coal. Although global industrial activity recovered in 2010 from 2009 levels, the continuation of the recovery, especially for industries in the United States and Europe, is uncertain. During recent years, financial markets in the United States, Europe and Asia also experienced unprecedented turmoil and upheaval. This was characterized by extreme volatility and declines in security prices, severely diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States federal government and other governments. Although we cannot predict the impacts, renewed weakness in the economic conditions of any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

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- demand for natural gas and electricity in the United States is impacted by industrial production, which if weakened would negatively impact the revenues, margins and profitability of our natural gas and thermal coal business;
- demand for metallurgical coal depends on steel demand in the United States and globally, which if weakened would negatively impact the revenues, margins and profitability of our metallurgical coal business including our ability to sell our high volatile steam coal as higher-priced metallurgical coal;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables and the amount of receivables eligible for sale pursuant to our accounts receivable securitization facility may decline;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business including for exploration and/or development of our coal or gas reserves; and
- our commodity hedging arrangements could become ineffective if our counterparties are unable to perform their

obligations or seek bankruptcy protection.

A significant or extended decline in the prices CONSOL Energy receives for our coal and natural gas could adversely affect our operating results and cash flows.

Our financial results are significantly affected by the prices we receive for our coal and natural gas. Extended or substantial price declines for coal would adversely affect our operating results for future periods and our ability to generate cash flows necessary to improve productivity and expand operations. Prices of coal may fluctuate due to factors beyond our control such as overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; increased utilization by the steel industry of electric arc furnaces or pulverized coal processes to make steel which do not use furnace coke, an intermediate product produced from metallurgical coal; technological advances affecting energy consumption; domestic and foreign government regulations; price and availability of alternative fuels; price of foreign imports; and weather conditions. Any adverse change in these factors could result in weaker demand and possibly lower prices for our coal production, which would reduce our revenues.
Gas prices are closely linked to supply of natural gas and consumption patterns in the United States of the electric power generation industry and certain industrial and residential patterns where gas is the principal fuel. Natural gas prices are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. In the past we have used hedging transactions to reduce our exposure to market price volatility when we deemed it appropriate. If we choose not to engage in, or reduce our use of hedging arrangements in the future, we may be more adversely affected by changes in natural gas prices than our competitors who engage in hedging arrangements to a greater extent than we do. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as: the domestic and foreign supply of natural gas; the price of foreign imports; overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; weather conditions; technological advances affecting energy consumption; domestic and foreign governmental regulations; proximity and capacity of gas pipelines and other transportation facilities; and the price and availability of alternative fuels. Many of these factors may be beyond our control. In particular, while demand for natural gas has recovered to pre-recession levels, the U.S. natural gas industry continues to face concerns of oversupply due to the success of new shale plays and continued drilling in these plays, despite lower gas prices, to meet drilling commitments. Lower natural gas prices may not only decrease our revenues on a per unit basis, but may also limit our access to capital. A significant decrease in price levels for an extended period would negatively affect us in several ways. These include reduced cash flow, which would decrease funds available for capital expenditures employed to replace reserves or increase production. For example, natural gas prices recently fell to ten year lows and we recently announced a significant reduction in the number of wells expected to be drilled in our Noble joint venture. Also, our access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable. Additionally, lower natural gas prices may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. We may incur impairment charges in the future, which could have an adverse effect on our results of operations in the period taken.
We expect in the future that we and our joint venture partners will increase drilling activity in areas of shale formations which may also contain natural gas liquids and/or oil. The prices for natural gas liquids and oil are volatile for reasons similar to those described above regarding natural gas. If we discover and produce significant amounts of natural gas liquids or oil, our results of operation may be adversely affected by downward fluctuations in natural gas

liquids and oil prices.

If coal customers do not extend existing contracts or do not enter into new long-term coal contracts, profitability of CONSOL Energy's operations could be affected.

During the year ended December 31, 2011, approximately 84% of the coal CONSOL Energy produced was sold under long-term contracts (contracts with terms of one year or more). If a substantial portion of CONSOL Energy's long-term contracts are modified or terminated or if force majeure is exercised, CONSOL Energy would be adversely affected if we are unable to replace the contracts or if new contracts are not at the same level of profitability. If existing customers do not honor current contract commitments, our revenue would be adversely affected. The profitability of our long-term coal supply contracts depends on a variety of factors, which vary from contract to contract and fluctuate during the contract term, including our production costs and other factors. Price changes, if any, provided in long-term supply contracts may not reflect our cost increases, and therefore, increases in our costs may reduce our profit margins. In addition, in periods of declining market prices, provisions in our long-term coal contracts for adjustment or renegotiation of prices and other provisions may increase our exposure to short-term coal price volatility. As a result, CONSOL Energy may not be able to obtain long-term agreements at favorable prices (compared to either market conditions, as they may change from time to time, or our cost structure) and long-term contracts may not contribute to our profitability.

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

For the year ended December 31, 2011, we derived over 10% of our total revenues from sales to one customer individually and more than 30% of our total revenue from sales to our four largest coal and gas customers. At December 31, 2011, we had approximately seventeen coal supply agreements with these customers that expire at various times from 2012 to 2028. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term coal supply agreements. If any one of these four customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal and gas sold and delivered depends on the continued creditworthiness of our customers. Some power plant owners may have credit ratings that are below investment grade. We also have been increasing exports to international customers and may have exposure to their creditworthiness. If the creditworthiness of our customers declines significantly, our $200 million accounts receivable securitization program and our business could be adversely affected. In addition, if customers refuse to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

The availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers. Similarly, our gas business depends on gathering, processing and transportation facilities owned by others and the disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our natural gas.

Coal producers depend upon rail, barge, trucking, overland conveyor and other systems to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lock-outs, break-downs of locks and dams or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability. 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 our coal less competitive.
We gather, process and transport our gas to market by utilizing pipelines and facilities owned by others. If pipelines and facilities do not exist near our producing wells, if pipeline or facility capacity is limited or if pipeline or facility capacity is unexpectedly disrupted, our gas sales could be limited, reducing our profitability. If we cannot access processing pipeline transportation facilities, we may have to reduce our production of gas or vent our produced gas to the atmosphere because we do not have facilities to store excess inventory. If our sales of gas are reduced because of transportation or processing constraints, our revenues will be reduced, and our unit costs will also increase. If pipeline quality tariffs change, we might be required to install additional processing equipment which could increase our costs. The pipeline could also curtail our flows until the gas delivered to their pipeline is in compliance.

Competition within the coal and natural gas industries may adversely affect our ability to sell our products. Increased competition or a loss of our competitive position could adversely affect our sales of, or our prices for, our coal and natural gas products, which could impair our profitability.

CONSOL Energy competes with coal producers in various regions of the United States and with some foreign coal producers for domestic sales primarily to electric power generators. CONSOL Energy also competes with both domestic and foreign coal producers for sales in international markets. Demand for our coal by our principal customers is affected by the delivered price of competing coals, other fuel supplies and alternative generating sources, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric and wind power. CONSOL Energy sells coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition. Increases in coal prices could encourage existing producers to expand capacity or could encourage new producers to enter the market. If overcapacity results, prices could fall or we may not be able to sell our coal, which would reduce revenue.

The gas industry is intensely competitive with companies from various regions of the United States. We compete with these companies and we may compete with foreign companies for domestic sales. Many of the companies we compete with are larger and have greater financial, technological, human and other resources. If we are unable to compete, our company, our operating results and financial position may be adversely affected. In addition, larger companies may be able to pay more to acquire new gas properties for future exploration, limiting our ability to replace natural gas we produce or to grow our production. Our ability to acquire additional properties and to discover new natural gas resources also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

We could be negatively affected if we fail to maintain satisfactory labor relations.

As of December 31, 2011, we had 9,157 employees. Approximately 32% of these employees are represented by the United Mine Workers of America (UMWA) and represented operations generated approximately 48% of our U.S. coal production during the year ended December 31, 2011. Relations with our employees and, where applicable, organized labor relations are important to our success. If we do not maintain satisfactory labor relations with our organized and non-represented employees, we may incur strikes, other work stoppages or have reduced productivity.
The characteristics of coal may make it costly for electric power generators and other coal users to comply with various environmental standards regarding the emissions of impurities released when coal is burned which could cause utilities to replace coal-fired power plants with alternative fuels. In addition, various incentives have been proposed to encourage the generation of electricity from renewable energy sources. A reduction in the use of coal for electric power generation could decrease the volume of our coal sales and adversely affect our results of operation.

Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air along with fine particulate matter and carbon dioxide when coal is burned. Complying with regulations on these emissions can be costly for electric power generators. For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users will need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), or switch to other fuels. Each option has limitations. Lower sulfur coal may be more costly to purchase on an energy basis than higher sulfur coal depending on mining and transportation costs. The cost of installing scrubbers is significant and emission allowances may become more expensive as their availability declines. Switching to other fuels may require expensive modification of existing plants. Because higher sulfur coal currently accounts for a significant portion of our sales, the extent to which electric power generators switch to alternative fuel could materially affect us. Adoption of the Cross-State Air Pollution Rule (CASPR) in July 2011 (to be effective January 1, 2012, but currently subject to a stay) and the Mercury and Air Toxic Standards Rule (MATS) in December 2011 requiring reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, and particulate matter may require the installation of additional costly control technology or the implementation of other measures, including trading of emission allowances and switching to alternative fuels. These additional reductions in permissible emission levels of impurities by coal-fired plants will likely make it more costly to operate coal-fired electric power plants and may make coal a less attractive fuel alternative for electric power generation in the future.

Apart from actual and potential regulation of emissions from coal-fired plants, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reductions in the amount of coal consumed by domestic electric power generators as a result of current or new standards for the emission of impurities or incentives to switch to alternative fuels or renewable energy sources could reduce the demand for our coal, thereby reducing our revenues and adversely affecting our business and results of operations.

Regulation of greenhouse gas emissions as well as uncertainty concerning such regulation could adversely impact the market for coal and natural gas and the regulation of greenhouse gas emissions may increase our operating costs and reduce the value of our coal and gas assets.

While climate change legislation in the U.S. is unlikely in the next several years, the issue of global climate change continues to attract considerable public and scientific attention with widespread concern about the impacts of human activity, especially the emissions of greenhouse gases (GHGs), such as carbon dioxide and methane. Combustion of fossil fuels, such as the coal and gas we produce, results in the creation of carbon dioxide emissions into the atmosphere by coal and gas end users, such as coal-fired electric power generation plants. Numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government that are intended to limit emissions of GHGs. Several states have already adopted measures requiring reduction of GHGs within state boundaries. Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (including the United States but has not been ratified by the United States) expires in 2012. Regulation of GHGs could occur in the United States pursuant to the Environmental Protection Agency (EPA) regulation under the Clean Air Act. On December 23, 2010 the EPA announced that it will propose standards for GHG emissions for gas, oil and coal fired power plants in July 2011 and issue final standards in May 2012. These proposed standards are now scheduled to be published in early 2012. Apart from governmental regulation, on February 4, 2008, three of Wall Street's largest investment banks announced that they had adopted climate change guidelines for lenders. The guidelines require the evaluation of carbon risks in the financing of electric power generation plants which may make it more difficult for utilities to obtain financing for coal-fired plants.
If comprehensive regulation focusing on GHGs emission reductions is adopted for the United States by the EPA or in other countries where we sell coal, or if utilities were to have difficulty obtaining financing in connection with coal-fired plants, it may make it more costly to operate fossil fuel fired (especially coal-fired) electric power generation plants and make fossil fuels less attractive for electric utility power plants in the future. Depending on the nature of the regulation or legislation, natural gas-fueled power generation could become more economically attractive than coal-fueled power generation, substantially increasing the demand for natural gas. Apart from actual regulation, uncertainty over the regulation of GHG emissions may inhibit utilities from investing in the building of new coal-fired plants to replace older plants or investing in the upgrading of existing coal-fired plants. Any reduction in the amount of coal or possibly natural gas consumed by domestic electric power generators as a result of actual or potential regulation of greenhouse gas emissions could decrease demand for our fossil fuels, thereby reducing our revenues and materially and adversely affecting our business and results of operations. We or our customers may also have to invest in carbon dioxide capture and storage technologies in order to burn coal or natural gas and comply with future GHG emission standards.

In addition, coalbed methane must be expelled from our underground coal mines for mining safety reasons. Coalbed methane has a greater GHG effect than carbon dioxide. Our gas operations capture coalbed methane from our underground coal mines, although some coalbed methane is vented into the atmosphere when the coal is mined. If regulation of GHG emissions does not exempt the release of coalbed methane, we may have to further reduce our methane emissions, pay higher taxes, incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines or perhaps curtail coal production. The amount of coalbed methane we capture is reported, on a voluntarily basis, to the U.S. Department of Energy. We have recorded the amounts we have captured since the early 1990's.

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

We compete in 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.

Our coal mining and natural gas operations are subject to operating risks, which could increase our operating expenses and decrease our production levels which could adversely affect our results of operations. Our coal and gas operations are also subject to hazards and any losses or liabilities we suffer from hazards which occur in our operations may not be fully covered by our insurance policies.

Our coal mining operations are predominantly underground mines. These mines are subject to a number of operating risks that could disrupt operations, decrease production and increase the cost of mining at particular mines for varying lengths of time thereby adversely affecting our operating results. In addition, if coal production declines, we may not be able to produce sufficient amounts of coal to deliver under our long-term coal contracts. CONSOL Energy's inability to satisfy contractual obligations could result in our customers initiating claims against us. The operating risks that may have a significant impact on our coal operations include:

- variations in thickness of the layer, or seam, of coal;
- amounts of rock and other natural materials intruding into the coal seam and other geological conditions that could affect the stability of the roof and the side walls of the mine;
- equipment failures or repairs;
- fires, explosions or other accidents;
- weather conditions; and
- security breaches or terroristic acts.

Our exploration for and production of natural gas also involves numerous operating risks. The cost of drilling, completing and operating our shale gas wells, shallow oil and gas wells and coalbed methane (CBM) wells is often uncertain, and a number of factors can delay or prevent drilling operations, decrease production and/or increase the cost of our gas operations at particular sites for varying lengths of time thereby adversely affecting our operating results. The operating risks that may have a significant impact on our gas operations include:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires, explosions or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- security breaches or terroristic acts;
- pipeline ruptures;
- lack of adequate capacity for treatment or disposal of waste water generated in drilling, completion and production operations;
- environmental contamination from surface spillage of fluids used in well drilling, completion or operation including fracturing fluids used in hydraulic fracturing of wells, or other contamination of groundwater or the environment resulting from our use of such fluids; and
- unavailability or high cost of drilling rigs, other field services and equipment.

Although we maintain insurance for a number of hazards, we may not be insured or fully insured against the losses or liabilities that could arise from a significant accident in our coal or gas operations.
A decrease in the availability or increase in the costs of commodities or capital equipment used in mining operations could decrease our coal production, impact our cost of coal production and decrease our anticipated profitability.

Coal mining consumes large quantities of commodities including steel, copper, rubber products and liquid fuels and requires the use of capital equipment. Some commodities, such as steel, are needed to comply with roof control plans required by regulation. The prices we pay for commodities and capital equipment are strongly impacted by the global market. A rapid or significant increase in the costs of commodities or capital equipment we use in our operations could impact our mining operations costs because we may have a limited ability to negotiate lower prices, and, in some cases, may not have a ready substitute.

We rely upon third party contractors to provide various field services to our coal and gas operations. A decrease in the availability of or an increase in the prices charged by third party contractors or failure of third party contractors to provide quality services to us in a timely manner could decrease our production, increase our costs of production, and decrease our anticipated profitability.

We rely upon third party contractors to provide key services to our gas operations. We contract with third parties for well services, related equipment, and qualified experienced field personnel to drill wells and conduct field operations. The demand for these field services in the natural gas and oil industry can fluctuate significantly. Higher oil and natural gas prices generally stimulate increased demand causing periodic shortages. These shortages may lead to escalating prices for drilling equipment, crews and associated supplies, equipment and services. Shortages may lead to poor service and inefficient drilling operations and increase the possibility of accidents due to the hiring of inexperienced personnel and overuse of equipment by contractors. In addition, the costs and delivery times of equipment and supplies are substantially greater in periods of peak demand. Accordingly, we cannot assure that we will be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we may experience shortages of, or increases in the costs of, drilling equipment, crews and associated supplies, equipment and field services in the future. We also use third party contractors to provide construction and specialized services to our mining operations. A decrease in the availability of field services or equipment and supplies, an increase in the prices charged for field services, equipment and supplies, or the failure of third party contractors to provide quality field services to us, could decrease our coal and gas production, increase our costs of coal and gas production, and decrease our anticipated profitability.

We attempt to mitigate the risks involved with increased industrial activity by entering into “take or pay” contracts with well service providers which commit them to provide field services to us at specified levels and commit us to pay for field services at specified levels even if we do not use those services. However, these contracts expose us to economic risk. For example, if the price of natural gas declines and it is not economical to drill and produce additional natural gas, we may have to pay for field services that we did not use. This would decrease our cash flow and raise our costs of production.

For mining and drilling operations, CONSOL Energy must obtain, maintain, and renew governmental permits and approvals which if we cannot obtain in a timely manner would reduce our production, cash flow and results of operations.

Most coal producers in the eastern U.S. are being impacted by government regulations and enforcement to a much greater extent than a few years ago, particularly in light of the renewed focus by environmental agencies and the government generally on the mining industry, including more stringent enforcement and interpretation of the laws that regulate mining. The pace with which the government issues permits needed for new operations and for on-going operations to continue mining has negatively impacted expected production, especially in Central Appalachia. Environmental groups in Southern West Virginia and Kentucky have challenged state and U.S. Army Corps of Engineers permits for mountaintop and types of surface mining operations on various grounds. The most recent challenges have focused on the adequacy of the Corps of Engineers analysis of impacts to streams and the adequacy of mitigation plans to compensate for stream impacts resulting from valley fill permits required for mountaintop mining. These challenges have also enhanced the EPA's oversight and involvement in the review of permits by state regulatory authorities. In 2007, the U.S. District Court for the Southern District of West Virginia found other operators' permits for mining in these areas to be deficient. In February 2009, the U.S. Court of Appeals for the Fourth Circuit reversed that decision, finding that the permits were adequate. However, since that reversal, the EPA began to more critically review valley fill permits and permits for all types of coal mining operations, and has been recommending that a number of permits be denied because of alleged concerns by the EPA of potential impacts to water quality in streams below mining operations, with cumulative impacts of mining on watersheds. The EPA's objections and an enhanced review process that was being implemented under a federal multi-agency memorandum of understanding effectively held up the issuance of permits for all types of mining operations that require Clean Water Act Section 402 discharge permits and Section 404 dredge and fill permits, including surface facilities for underground mines. Although a portion of the EPA's enhanced review process was invalidated in October 2011, in part because the EPA failed to follow public notice and rulemaking requirements, normal permitting has not resumed. Also, the EPA may elect to seek to adopt regulations to codify its enhanced review process. CONSOL Energy's surface and underground operations have been impacted to a limited extent to date, but future permits may be delayed if the EPA continues to seek to exercise enhanced oversight and involvement in state permit programs. In addition, the length of time needed to bring a new mine into production has increased by several years because of the increased time required to obtain necessary permits. These delays or denials of mining permits could reduce our production, cash flow and results of operations.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, and others that govern our business may increase our costs of doing business for both coal and natural gas, and may restrict both our coal and gas operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities relating to protection of the environment. These include those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the cleanup of contaminated sites, groundwater quality and availability, threatened and endangered plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, the installation of various safety equipment in our mines, remediation of impacts of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations and competitive position. For example, we have agreed to commence operation by May 30, 2013, of a new advanced waste water treatment plant to treat the discharge of mine water from our Blacksville #2, Loveridge and Robinson Run mines at a total estimated cost of approximately $200 million. In addition, we could incur substantial costs as a result of violations under environmental laws. Any additional laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities or new interpretations of existing legal requirements by regulatory bodies relating to the protection of the environment matters could further affect our costs of operations and competitive position.

For example, the federal Clean Water Act and corresponding state laws affect coal mining and gas operations by imposing restrictions on discharges into regulated surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The Clean Water Act federal regulations and corresponding state laws and regulations require permits for discharges from mining and gas operations that include discharge limits that are adequate to protect existing stream uses and aquatic life and, for impaired streams, that are adequate to eliminate the impairment, which may cause CONSOL Energy to incur additional costs that could adversely affect our operating results, financial condition and cash flows or may prevent us from being able to mine portions of our reserves. The Clean Water Act is being used by opponents of mountain top removal mining as a means to challenge permits. In addition, CONSOL Energy incurs and will continue to incur costs associated with the investigation and remediation of environmental contamination under the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) and similar state statutes and has been named as a potentially responsible party at Superfund sites in the past.

State and local authorities regulate various aspects of gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing and well site restoration. If we fail to comply with statutes and regulations, we may be subject to penalties, which would decrease our profitability.

Additionally, regulations applicable to the gas industry are under constant review for amendment or expansion at the federal and state level. Any future changes may affect, among other things, the pricing or marketing of gas production. For example, hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as Marcellus shale. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Hydraulic fracturing is currently exempt from regulation under the federal Safe Drinking Water Act, except for hydraulic fracturing using diesel fuel. The disposal of produced water, drilling fluids and other wastes in underground injection disposal wells is regulated by the EPA under the federal Safe Drinking Water Act or by the states under counterpart state laws and regulations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing operations or to dispose of waste resulting from such operations. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and with a final report to be issued in 2014. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy (DOE), the U.S. Government Accountability Office and the Department of the Interior. In addition, legislation has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances. If hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Further, some state and local governments in the Marcellus Shale region in Pennsylvania and New York have considered or imposed a temporary moratorium on drilling operations using hydraulic fracturing until further study of the potential for environmental and human health impacts by the EPA or the relevant agencies are completed. No assurance can be given as to whether or not similar measures might be considered or implemented in other jurisdictions in which our gas properties are located. If new laws or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in states in which we operate, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. New laws or regulations could also cause delays or interruptions or terminations of operations, the extent of which cannot be predicted, and could reduce the amount of oil and natural gas that we ultimately are able to produce in commercially paying quantities from our gas properties, all of which could have a material adverse affect on our results of operation and financial condition.

Our shale gas drilling and production operations require both adequate sources of water to use in the fracturing process as well as the ability to dispose of water and other wastes after hydraulic fracturing. Our CBM gas drilling and production operations also require the removal and disposal of water from the coal seams from which we produce gas. If we cannot find adequate sources of water for our use or are unable to dispose of the water we use or remove it from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas economically and in commercial quantities could be impaired.

As part of our drilling and production in the Marcellus shale, we use hydraulic fracturing processes. Thus, we need access to adequate sources of water to use in our Marcellus shale operations. Further, we must remove and dispose of the portion of the water that we use to fracture our shale gas wells that flows back to the well-bore as well as drilling fluids and other wastes associated with the exploration, development or production of natural gas. In addition, in our CBM drilling and production, coal seams frequently contain water that must be removed and disposed of in order for the gas to detach from the coal and flow to the well bore. Our inability to locate sufficient amounts of water with respect to our Marcellus Shale operations, or the inability to dispose of or recycle water and other wastes used in our Marcellus shale and our CBM operations, could adversely impact our operations. For example, in Ohio, injection of gas well production fluids was temporarily suspended for underground injection disposal wells near Youngstown while regulatory authorities investigate whether injection of wastewater into the wells is causing low category earthquakes in the area.

Our mines are subject to stringent federal and state safety regulations that increase our cost of doing business at active operations and may place restrictions on our methods of operation. In addition, government inspectors under certain circumstances, have the ability to order our operations to be shut down based on safety considerations. A mine could be shut down for an extended period of time if a disaster were to occur at it.

Stringent health and safety standards were imposed by federal legislation when the Federal Coal Mine Health and Safety Act of 1969 was adopted. The Federal Coal Mine Safety and Health Act of 1977 expanded the enforcement of safety and health standards of the Coal Mine Health and Safety Act of 1969 and imposed safety and health standards on all (non-coal as well as coal) mining operations. Regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, the equipment used in mine emergency procedures, mine plans and other matters. The additional requirements of the Mine Improvement and New Emergency Response Act of 2006 (the Miner Act) and implementing federal regulations include, among other things, expanded emergency response plans, providing additional quantities of breathable air for emergencies, installation of refuge chambers in underground coal mines, installation of two-way communications and tracking systems for underground coal mines, new standards for sealing mined out areas of underground coal mines, more available mine rescue teams and enhanced training for emergencies. Most states in which CONSOL Energy operates have programs for mine safety and health regulation and enforcement. We believe that the combination of federal and state safety and health regulations in the coal mining industry is, perhaps, the most comprehensive system for protection of employee safety and health affecting any industry. Most aspects of mine operations, particularly underground mine operations, are subject to extensive regulation. The various requirements mandated by law or regulation can place restrictions on our methods of operations, creating a significant effect on operating costs and productivity. In addition, government inspectors under certain circumstances, have the ability to order our operation to be shut down based on safety considerations. If a disaster were to occur at one of our mines, it could be shutdown for an extended period of time and our reputation with our customers could be materially damaged.

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

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as “acid mine drainage.” We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or for the entire share.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Our coal refuse areas and slurry impoundments are designed, constructed, and inspected by our company and by regulatory authorities according to stringent environmental and safety standards. Structural failure of a slurry impoundment or coal refuse area could result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

In West Virginia there are areas where drainage from coal mining operations contains concentrations of selenium that without treatment would result in violations of state water quality standards that are set to protect fish and other aquatic life. CONSOL Energy has two operations with selenium discharges. CONSOL Energy and other coal companies are working to expeditiously develop cost effective means to remove selenium from mine water. If such technology is not developed promptly, the only available effective treatment technologies are expensive to construct and operate which will increase coal production costs.

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

CONSOL Energy has reclamation, mine closing and gas well plugging obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

The Surface Mining Control and Reclamation Act establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Also, state laws require us to plug gas wells and reclaim well sites after the useful life of our gas wells has ended. CONSOL Energy accrues for the costs of current mine disturbance, gas well plugging and of final mine closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing liabilities and gas well plugging, which are based upon permit requirements and our experience, were approximately $650 million at December 31, 2011. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. Furthermore, these obligations are unfunded. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.
Most states where we operate require us to post bonds for the full cost of coal mine reclamation (full cost bonding). West Virginia is not a full cost bonding state. West Virginia has an alternative bond system (ABS) for coal mine reclamation which consists of (i) individual site bonds posted by the permittee that are less than the full estimated reclamation cost plus (ii) a bond pool (Special Reclamation Fund) funded by a per ton fee on coal mined in the State which is used to supplement the site specific bonds if needed in the event of bond forfeiture. The Special Reclamation Fund is currently underfunded. Adequacy of the Special Reclamation Fund is an issue in a citizen suit pending in U.S. District Court in West Virginia. Given these facts, it is likely that funding for the Special Reclamation Fund will be increased to make it solvent through an increase in the per ton fee or from other funding sources, or the State may be forced by the court or the U.S. Office of Surface Mine Reclamation and Enforcement to convert to full cost bonding. An increase in the per ton fee may reduce profit margins and/or make some operations unprofitable. Conversion to full cost bonding may exceed bonding capacity of individual mining companies and/or surety companies that would result in the need to post cash bonds or letters of credit which would reduce operating capital.

CONSOL Energy faces uncertainties in estimating our economically recoverable coal and gas reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

There are 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 our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs, including the cost of materials.

In addition, we hold substantial coal reserves in areas containing Marcellus shale and other shales. These areas are currently the subject of substantial exploration for oil and gas, particularly by horizontal drilling. If a well is in the path of our mining for coal, we may not be able to mine through the well unless we purchase it. Although in the past we have purchased vertical wells, the cost of purchasing a producing horizontal well could be substantially greater. Horizontal wells with multiple laterals extending from the well pad may access larger oil and gas reserves than a vertical well which could result in higher costs. In future years, the cost associated with purchasing oil and gas wells which are in the path of our coal mining may make mining through those wells uneconomical thereby effectively causing a loss of significant portions of our coal reserves.

Similarly, natural gas reserves require subjective estimates of underground accumulations of natural gas and assumptions concerning natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved gas reserves and projections of future production rates and the timing of development expenditures may be incorrect. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing and production. Also, we make certain assumptions regarding natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our gas reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of gas reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates. The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved gas reserves on historical average prices and costs. However, actual future net cash flows from our gas and oil properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- assumptions governing future prices;
- future operating costs; and
- capital costs of drilling new wells.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. In addition, if natural gas prices decline by $0.10 per thousand cubic feet, then the pre-tax present value using a 10% discount rate of our proved gas reserves as of December 31, 2011 would decrease from $2.9 billion to $2.7 billion. The standardized Generally Accepted Accounting Principle measure associated with this decline of $0.10 per thousand cubic feet, would be approximately $1.7 billion.

Each of the factors which impacts reserve estimation may in fact vary considerably from the assumptions used in estimating the reserves. For these reasons, estimates of coal and gas reserves may vary substantially. Actual production, revenues and expenditures with respect to our coal and gas reserves will likely vary from estimates, and these variances may be material. As a result, our estimates may not accurately reflect our actual coal and gas reserves.

We may incur additional costs and delays to produce coal and gas because we have to acquire additional property rights to perfect our title to coal or gas rights.

While chain of title for our coal estate generally has been established, there may be defects in it that we do not realize until we have committed to developing those properties or coal reserves. As such, the title to the coal estate that we intend to mine may contain defects. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs perfecting title.

Substantial amounts of acreage in which we believe we control gas rights are in areas where we have not yet done a thorough chain of title examination of the gas estate. A number of our gas properties were acquired primarily for the coal rights with the focus on the coal estate title, and, in many cases were acquired years ago. In addition, we have acquired gas rights in substantial acreage from third parties who had not performed thorough chain of title work on their gas properties. Our practice, and we believe industry practice, is not to perform a thorough title examination on gas properties until shortly before the commencement of drilling activities at which time we seek to acquire any additional rights needed to perfect our ownership of the gas estate for development and production purposes. We may incur substantial costs to acquire these additional property rights and the acquisition of the necessary rights may not be feasible in some cases. Our inability to obtain these rights may adversely impact our ability to develop those properties. Some states permit us to produce the gas without perfected ownership under an administrative process known as “pooling,” which require us to give notice to all potential claimants and pay royalties into escrow until the undetermined rights are resolved. As a result, we may have to pay royalties to produce gas on acreage that we control and these costs may be material. Further, the pooling process is time-consuming and may delay our drilling program in the affected areas.

In confirming title to the gas estate in Pennsylvania, we rely upon long standing Pennsylvania Supreme Court decisions. A recent decision by the intermediate appellate court in Pennsylvania in a case captioned Butler v. Powers (Pa. Superior Ct., No. 1795 MDA 2010) did not change the law of Pennsylvania, but in remanding the case to the trial court for further proceedings, it called into question the applicability of a long-standing presumption known as the Dunham Rule to gas in the Marcellus Shale. The Dunham Rule is a presumption that a reservation or conveyance of minerals does not transfer the ownership of oil and gas absent an express reference to oil and gas. While we believe that the Pennsylvania courts will ultimately confirm that the Dunham Rule applies to Marcellus Shale gas, if the Pennsylvania courts were to hold otherwise, we could be exposed to lawsuits challenging our rights to Marcellus Shale gas in some of our Pennsylvania properties where our rights derive from persons who did not also own the mineral rights and we may have to incur substantial additional costs to perfect our gas title in those Pennsylvania properties.

Our subsidiaries, primarily Fairmont Supply Company, is a co-defendant in various asbestos litigation cases which could result in making payments in the future that are material.

One of our subsidiaries, Fairmont Supply Company (Fairmont), which distributes industrial supplies, currently is named as a defendant in approximately 7,500 asbestos claims in state courts in Pennsylvania, Ohio, West Virginia, Maryland, New Jersey, Texas and Illinois. Because a very small percentage of products manufactured by third parties and supplied by Fairmont in the past may have contained asbestos and many of the pending claims are part of mass complaints filed by hundreds of plaintiffs against a hundred or more defendants, it has been difficult for Fairmont to determine how many of the cases actually involve valid claims or plaintiffs who were actually exposed to asbestos-containing products supplied by Fairmont. In addition, while Fairmont may be entitled to indemnity or contribution in certain jurisdictions from manufacturers of identified products, the availability of such indemnity or contribution is unclear at this time and, in recent years, some of the manufacturers named as defendants in these actions have sought protection from these claims under bankruptcy laws. Fairmont has no insurance coverage with respect to these asbestos cases. For the year ended December 31, 2011, payments by Fairmont with respect to asbestos cases have not been material. Other of our subsidiaries may also have asbestos claims against them. Our current estimates related to these asbestos claims, individually and in the aggregate, are immaterial to the financial position, results of operations and cash flows of CONSOL Energy. However, it is reasonably possible that payments in the future with respect to pending or future asbestos cases may be material to the financial position, results of operations or cash flows of CONSOL Energy.

CONSOL Energy and its subsidiaries are subject to various legal proceedings, which may have an adverse effect on our business.

We are party to a number of legal proceedings in the normal course of business activities. Defending these actions, especially purported class actions, can be costly, and can distract management. For example, we are a defendant in five pending purported class action lawsuits dealing with such diverse matters as the propriety of our acquisition of the noncontrolling interest of CNX Gas, our right to natural gas production in some areas, and asserting that we are responsible for Hurricane Katrina and the damage it caused. There is the potential that the costs of defending litigation in 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 Note 24–Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion of pending legal proceedings.

CONSOL Energy has obligations for long-term employee benefits for which we accrue based upon assumptions which, if inaccurate, could result in CONSOL Energy being required to expense greater amounts than anticipated.

CONSOL Energy provides various long-term employee benefits to inactive and retired employees. We accrue amounts for these obligations. At December 31, 2011, the current and non-current portions of these obligations included:

- postretirement medical and life insurance ($3.2 billion);
- coal workers' black lung benefits ($183.6 million);
- salaried retirement benefits ($274.8 million); and
- workers' compensation ($174.1 million).

However, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Salary retirement benefits are funded in accordance with Employer Retirement Income Security Act of 1974 (ERISA) regulations. The other obligations are un-funded. In addition, the federal government and several states in which we operate consider changes in workers' compensation and black lung laws from time to time. Such changes, if enacted, could increase our benefit expense.

Due to our participation in an underfunded multi-employer pension plan, we have exposure under that plan that extends beyond what our obligation would be with respect to our employees and in the future we may have to make additional cash contributions to fund the pension plan or incur withdrawal liability.

Certain of our subsidiaries have been contributing to a multi-employer defined benefit pension plan (1974 Pension Trust) for United Mine Workers of America (UMWA) retirees under the terms of various National Bituminous Coal Wage Agreements (NBCWA) which those subsidiaries have entered into over the years with the UMWA. The current NBCWA with the UMWA became effective July 1, 2011 and expires on December 31, 2016. All assets contributed to the 1974 Pension Trust are pooled and available to provide benefits for all participants and beneficiaries. As a result, contributions made by our signatory subsidiaries benefit employees of CONSOL Energy and of other employers. For the plan year ended June 30, 2011, approximately 18% of retirees and surviving spouses receiving benefits from the 1974 Pension Trust last worked at signatory subsidiaries of CONSOL Energy. The 1974 Pension Trust is overseen by a board of trustees, consisting of two union-appointed trustees and two employer-appointed trustees. The trustees' responsibilities include selection of the plan's investment policy, asset allocation, individual investment of plan assets and the administration of the plan. The benefits provided by the 1974 Pension Trust to the participating employees are determined based on age and years of service at retirement. The current NBCWA calls for contribution amounts to be paid to the 1974 Pension Trust by our signatory subsidiaries during the term of the NBCWA based principally on hours worked by our UMWA-represented employees at a contribution rate of $5.50 per hour.

As of June 30, 2011, the most recent date for which information is available, the 1974 Pension Trust was underfunded. This determination was made in accordance with Employer Retirement Income Security Act of 1974 (ERISA) calculations, with a total actuarial asset value of $5.1 billion and a total actuarial accrued liability of $6.6 billion. Under the Pension Protection Act of 2006 (Pension Protection Act), a funded percentage of 80% should be maintained for this multi-employer pension plan, and if the plan is determined to have a funded percentage of less than 80% it will be deemed to be "endangered" or "seriously endangered" if the number of years to reach a projected funding deficiency equals 7 or less and if less than 65%, it will be deemed to be in "critical" status. The funded percentage certified by the actuary for the 1974 Pension Trust was determined to be approximately 76.5% under the Pension Act. On October 21, 2011, the signatory subsidiaries of CONSOL Energy received notice from the trustees of the 1974 Pension Trust stating that the 1974 Pension Plan is considered to be in "seriously endangered" status for the plan year beginning July 1, 2011 due to the funded percentage and projected funding deficiency. As a result, the Pension Protection Act requires the 1974 Pension Trust to adopt a funding improvement plan no later than May 25, 2012, to improve the funded status of the plan, which may include increased contributions to the 1974 Pension Trust from employers in the future. Because the 2011 NBCWA established our signatory subsidiaries contribution obligations through December 31, 2016, our signatory subsidiaries' contributions to the 1974 Pension Trust should not increase during the term of the NBCWA as a consequence of any funding improvement plan adopted by the 1974 Pension Trust to address the plan's seriously endangered status.

Upon expiration of the 2011 NBCWA, our signatory subsidiaries could be required to increase contributions to the 1974 Pension Trust in amounts that could be material to our financial position and results of operations or cash flows. In the event our subsidiaries were to withdraw from the 1974 Pension Trust, CONSOL Energy and its subsidiaries would be liable for a proportionate share of such pension plan's unfunded vested benefits, as determined by the plan's actuary. Based on the information available from the 1974 Pension Trust's administrators, we believe that our portion of the contingent liability represented by the plan's unfunded vested benefits, in the case of the withdrawal of our signatory subsidiaries from the plan or in the case of the termination of the plan, would be material to our financial position and results of operations. As of June 30, 2011 this withdrawal liability was estimated at approximately $1.2 billion. In the event that any other contributing employer withdraws from the 1974 Pension Trust and such employer (or any member in its controlled group) cannot satisfy their obligations under the plan at the time of withdrawal, then we, along with the other remaining contributing employers, would be liable for an increase in our proportionate share of the 1974 Pension Trust's unfunded vested benefits at the time of the withdrawal from the plan or its termination.

If lump sum payments made to retiring salaried employees pursuant to CONSOL Energy's defined benefit pension plan exceed the total of the service cost and the interest cost in a plan year, CONSOL Energy would need to make an adjustment to operating results equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum payment in that year, which may result in an adjustment that could reduce operating results.

CONSOL Energy's defined benefit pension plan for salaried employees allows such employees to receive a lump-sum distribution for benefits earned up through December 31, 2005 in lieu of annual payments when they retire from

CONSOL Energy. Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans for Terminations Benefits requires that if the lump-sum distributions made for a plan year exceed the total of the service cost and interest cost for the plan year, CONSOL Energy would need to recognize for that year's results of operations an adjustment equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum in that year. This type of adjustment may result in a reduction in operating results.

Acquisitions that we have completed, acquisitions that we may undertake in the future, as well as expanding existing company mines, involve a number of risks, any of which could cause us not to realize the anticipated benefits and to the extent we plan to engage in joint ventures and divestitures, we do not control the timing of these and they may not provide anticipated benefits.

We have completed several acquisitions and investments in the past including the approximately $3.5 billion Dominion

Acquisition, which closed on April 30, 2010. We also continually seek to grow our business by adding and developing coal and gas reserves through acquisitions and by expanding the production at existing mines and existing gas operations. If we are unable to successfully integrate the companies, businesses or properties we acquire, we may fail to realize the expected benefits of the acquisition and our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Acquisitions, mine expansion and gas operation expansion involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of expansion and acquisition opportunities;
- 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 expansion or an acquisition opportunity;
- the potential revision of assumptions regarding gas reserves as we acquire more knowledge by operating an acquired gas business;
- problems that could arise from the integration of the acquired business;
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or the acquisition opportunity; and
- we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions.

From time to time part of our business and financing plans include entering into joint venture arrangements and the divestiture of certain assets. However, we do not control the timing of divestitures or joint venture arrangements and delays in entering into divestitures or joint venture arrangements may reduce the benefits from them. In addition, the terms of divestitures and joint venture arrangements may make a substantial portion of the benefits we anticipate receiving from them to be subject to future matters that we do not control.

We have entered into two significant gas joint ventures. These joint ventures restrict our operational and corporate flexibility; actions taken by our joint venture partners may materially impact our financial position and results of operation; and we may not realize the benefits we expect to realize from these joint ventures.

In the second half of 2011 CONSOL Energy, through its principal gas operations subsidiary, CNX Gas Company LLC (CNX Gas Company), entered into joint venture arrangements with Noble Energy, Inc. (Noble Energy) and Hess Ohio Developments, LLC (Hess) regarding our shale gas assets. We sold a 50% undivided interest in approximately 628 thousand net acres of Marcellus shale oil and gas assets to Noble Energy and a 50% undivided interest in nearly 200 thousand net Utica shale acres in Ohio. The following aspects of these joint ventures could materially impact CONSOL Energy:

- The development of these properties is subject to the terms of our joint development agreements with these parties and we no longer have the flexibility to control the development of these properties. For example, the joint development agreements for each of these joint ventures sets forth required capital expenditure programs that each party must participate in unless the parties mutually agree to change such programs or, in certain limited circumstances in the case of the Noble Energy joint development agreement, a party elects to exercise a non-consent right with respect to an entire year. If we do not timely meet our financial commitments under the respective joint venture agreements, our rights to participate in such joint ventures will be adversely affected and the other parties to the joint ventures may have a right to acquire a share of our interest in such joint ventures proportionate to, and in satisfaction of, our unmet financial obligations. In addition, each joint venture party has the right to elect to participate in all acreage and other acquisitions in certain defined areas of mutual interest.
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Each joint development agreement assigns to each party designated areas over which that party will manage and control operations. We could incur liability as a result of action taken by one of our joint venture partners.

- Of the approximately $3.3 billion we anticipate receiving from Noble Energy, approximately $2.1 billion depends upon Noble Energy paying a portion of our share of drilling and development costs for new wells, which we call “carried costs.” We entered into a similar transaction with Hess Ohio Developments, LLC (Hess) in which approximately $534 million of the total anticipated consideration of $594 million is dependent upon Hess paying carried costs. Thus, the benefits we anticipate receiving in the joint ventures depend in part upon the rate at which new wells are drilled and developed in each joint venture, which could fluctuate significantly from period to period. Moreover, the performance of these third party obligations is outside our control. The inability or failure of a joint venturer to pay its portion of development costs, including our carried costs during the carry period, could increase our costs of operations or result in reduced drilling and production of oil and gas or loss of rights to develop the oil and gas properties held by that joint venture;

- Noble Energy's obligation to pay carried costs is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per million British thermal units or "MMBtu" in any three consecutive month period and will remain suspended until average natural gas prices are above $4.00/MMBtu for three consecutive months. As a result of this provision, Noble Energy's obligation to pay carried costs was suspended beginning on December 1, 2011. We cannot predict when this suspension will be lifted and Noble Energy's obligation to pay the carried costs will resume. This suspension has the effect of requiring us to incur our entire 50 percent share of the drilling and completion costs for new wells during the suspension period and delaying receipt of a portion of the value we expect to receive in the transaction.
- The Noble Energy joint development agreement prohibits prior to March 31, 2014, unless Noble Energy consents in its sole discretion, any transfer of our interests in the Noble Energy joint venture assets or our selling or otherwise transferring control of CNX Gas Company. The Hess joint development agreement prohibits prior to October 21, 2014, unless Hess consents in its sole discretion, any transfer of our interests in the Hess joint venture assets. These restrictions may preclude transactions which could be beneficial to our shareholders.
- Disputes between us and our joint venture partners may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

We may also enter into other joint venture arrangements in the future which could pose risks similar to risks described above.

CONSOL Energy's rights plan may have anti-takeover effects that may discourage a change of control even if doing so might be beneficial to our stockholders.

On December 19, 2003, CONSOL Energy adopted a rights plan which, in certain circumstances, including a person or group acquiring, or the commencement of a tender or exchange offer that would result in a person or group acquiring, beneficial ownership of more than 15% of the outstanding shares of CONSOL Energy common stock, would entitle each right holder to receive, upon exercise of the right, shares of CONSOL Energy common stock having a value equal to twice the right exercise price. For example, at an exercise price of $80 per right, each right not otherwise voided would entitle its holders to purchase $160 worth of shares of CONSOL Energy common stock for $80. Assuming that shares of CONSOL Energy common stock had a per share value of $16 at such time, the holder of each right would be entitled to purchase ten shares of CONSOL Energy common stock for $80, or a price of $8 per share, one half of its then market price. This and other provisions of CONSOL Energy's rights plan could make it more difficult for a third party to acquire CONSOL Energy, which could hinder stockholders' ability to receive a premium for CONSOL Energy stock over the prevailing market prices.

The provisions of our debt agreements and the risks associated with our debt could adversely affect our business, financial condition and results of operations.

As of December 31, 2011, our total indebtedness was approximately $3.198 billion of which approximately $1.5 billion was under our 8.00% senior unsecured notes due April 2017, $1.25 billion was under our 8.25% senior unsecured notes due April 2020, $250 million was under our 6.375% senior notes due 2021, $103 million was under our Baltimore Port Facility 5.75% revenue bonds due September 2025, $64 million of capitalized leases due through 2021, and $31 million of miscellaneous debt. The degree to which we are leveraged could have important consequences, including, but not limited to:

- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, development of our coal and gas reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal and gas industries; and

- placing us at a competitive disadvantage compared to less leveraged competitors.

Our senior secured credit facility and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes limit the incurrence of additional indebtedness unless specified tests or exceptions are met. In addition, our senior secured credit agreement and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes subject us to financial and/or other restrictive covenants. Under our senior secured credit agreement, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio, a maximum leverage ratio, and a maximum senior secured leverage ratio, as defined. Our senior secured credit agreement and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes impose a number of restrictions upon us, such as restrictions on granting liens on our assets, making investments, paying dividends, selling assets and engaging in acquisitions. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have an adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our senior secured credit agreement and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

Unless we replace our gas reserves, our gas reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2011, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To manage our exposure to fluctuations in the price of natural gas, we enter into hedging arrangements with respect to a portion of our expected production. As of December 31, 2011, we had hedges on approximately 76.9 billion cubic feet of our 2012 natural gas production, 50.8 billion cubic feet of our 2013 natural gas production, 44.0 billion cubic feet of our 2014 natural gas production, and 3.8 billion cubic feet of our 2015 natural gas production. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our contracts fail to perform the contracts; or
- the creditworthiness of our counterparties or their guarantors is substantially impaired.

If our gas hedges would no longer qualify for hedge accounting, we will be required to mark them to market and recognize the adjustments through current year earnings. This may result in more volatility in our income in future periods.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

See “Coal Operations” and “Gas Operations” in Item 1 of this 10-K for a description of CONSOL Energy's properties.

ITEM 3. Legal Proceedings

The first through the nineteenth paragraphs of Note 24–Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K are incorporated herein by reference.

ITEM 4. Mine Safety and Health Administration Safety Data

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this annual report.

PART II

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

Our common stock is listed on the New York Stock Exchange under the symbol CNX. The following table sets forth for the periods indicated the range of high and low sales prices per share of our common stock as reported on the New York Stock Exchange and the cash dividends declared on the common stock for the periods indicated:

	High	Low	Dividends
Year Period Ended December 31, 2011			
Quarter Ended March 31, 2011	$55.49	$45.49	$0.100
Quarter Ended June 30, 2011	$54.17	$45.86	$0.100
Quarter Ended September 30, 2011	$54.82	$33.93	$0.100
Quarter Ended December 31, 2011	$46.75	$31.70	$0.125
Year Period Ended December 31, 2010			
Quarter Ended March 31, 2010	$56.34	$42.28	$0.100
Quarter Ended June 30, 2010	$46.26	$33.73	$0.100
Quarter Ended September 30, 2010	$39.22	$31.21	$0.100
Quarter Ended December 31, 2010	$48.81	$36.67	$0.100

As of December 31, 2011, there were 172 holders of record of our common stock.
The following performance graph compares the yearly percentage change in the cumulative total shareholder return on the common stock of CONSOL Energy to the cumulative shareholder return for the same period of a peer group and the Standard & Poor's 500 Stock Index. The peer group is comprised of CONSOL Energy, Alliance Resource Partners, Alpha Natural Resources Inc., Anadarko Petroleum Corp., Apache Corp., Arch Coal Inc., Cabot Oil & Gas Corp., Callon Petroleum Co., Chesapeake Energy Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Devon Energy Corp., Encana Corp., EOG Resources Inc., James River Coal Co., Newfield Exploration Co., Nexen Inc., Noble Energy Inc., Peabody Energy Corp., Penn Virginia Corp., Pioneer Natural Resources Co., Rio Tinto PLC (ADR), St Mary Land & Exploration, Stone Energy Corp., Ultra Petroleum Corp., and Westmoreland Coal Co. The graph assumes that the value of the investment in CONSOL Energy common stock and each index was $100 at December 31, 2006. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2011.

	2006	2007	2008	2009	2010	2011
CONSOL Energy Inc.	100.0	223.6	90.6	159.0	157.0	119.6
Peer Group	100.0	182.8	66.9	118.2	150.1	112.8
S&P 500 Stock Index	100.0	105.4	66.8	84.1	96.7	96.7

Cumulative Total Shareholder Return Among CONSOL Energy Inc., Peer Group and S&P 500 Stock Index

The above information is being furnished pursuant to Regulation S-K, Item 201 (e) (Performance Graph).
On January 27, 2012, CONSOL Energy's board of directors declared a regular quarterly dividend of $0.125 per share, payable on February 21, 2012, to shareholders of record on February 7, 2012.

On October 27, 2011, CONSOL Energy's Board of Directors increased the regular annual dividend by 25%, or $0.10 per share, to $0.50 per share, effective immediately.

The declaration and payment of dividends by CONSOL Energy is subject to the discretion of CONSOL Energy's Board of Directors, and no assurance can be given that CONSOL Energy will pay dividends in the future. CONSOL Energy's Board of Directors determines whether dividends will be paid quarterly. The determination to pay dividends will depend upon, among other things, general business conditions, CONSOL Energy's financial results, contractual and legal restrictions regarding the payment of dividends by CONSOL Energy, planned investments by CONSOL Energy and such other factors as the Board of Directors deems relevant. Our credit facility limits our ability to pay dividends in excess of an annual rate of $0.40 per share when our leverage ratio exceeds 4.50 to 1.00 or our availability is less than or equal to $100 million. The leverage ratio was 2.15 to 1.00 and our availability was approximately $1.2 billion at December 31, 2011. The credit facility does not permit dividend payments in the event of default. The indentures to the 2017, 2020 and 2021 notes limit dividends to $0.40 per share annually unless several conditions are met. Conditions include no defaults, ability to incur additional debt and other payment limitations under the indentures. There were no defaults in the year ended December 31, 2011.
See Part III, Item 12. "Security ownership of Certain Beneficial Owners and Management and Related Stockholders Matters" for information relating to CONSOL Energy's equity compensation plans.

ITEM 6. Selected Financial Data

The following table presents our selected consolidated financial and operating data for, and as of the end of, each of the periods indicated. The selected consolidated financial data for, and as of the end of, each of the years ended December 31, 2011, 2010, 2009, 2008 and 2007 are derived from our audited Consolidated Financial Statements. Certain reclassifications of prior year data have been made to conform to the year ended December 31, 2011 presentation. The selected consolidated financial and operating data are not necessarily indicative of the results that may be expected for any future period. The selected consolidated financial and operating data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes included in this annual report.

STATEMENT OF INCOME DATA
(In thousands except per share data)

	For the Years Ended December 31,				
	2011	2010	2009	2008	2007
Sales–Outside(A)	$5,660,813	$4,938,703	$4,311,791	$4,181,569	$3,324,346
Sales–Gas Royalty Interest(A)	66,929	62,869	40,951	79,302	46,586
Sales–Purchased Gas(A)	4,344	11,227	7,040	8,464	7,628
Freight–Outside(A)	231,536	125,715	148,907	216,968	186,909
Other Income	153,620	97,507	113,186	166,142	196,728
Total Revenue and Other Income	6,117,242	5,236,021	4,621,875	4,652,445	3,762,197
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	3,501,189	3,262,327	2,757,052	2,843,203	2,352,000
Gas Royalty Interests' Costs	59,331	53,775	32,376	73,962	39,921
Purchased Gas Costs	3,831	9,736	6,442	8,175	7,162
Freight Expense	231,347	125,544	148,907	216,968	186,909
Selling, General and Administrative Expenses	175,576	150,210	130,704	124,543	108,664
Depreciation, Depletion and Amortization	618,397	567,663	437,417	389,621	324,715
Interest Expense	248,344	205,032	31,419	36,183	30,851
Taxes Other Than Income	344,460	328,458	289,941	289,990	258,926
Abandonment of Long-Lived Assets	115,817	—	—	—	—
Loss on Debt Extinguishment	16,090	—	—	—	—
Transaction and Financing Fees	14,907	65,363	—	—	—
Black Lung Excise Tax Refund	—	—	(728)	(55,795)	24,092
Total Costs	5,329,289	4,768,108	3,833,530	3,926,850	3,333,240
Earnings Before Income Taxes	787,953	467,913	788,345	725,595	428,957
Income Taxes	155,456	109,287	221,203	239,934	136,137
Net Income	632,497	358,626	567,142	485,661	292,820
Less: Net Income Attributable to Noncontrolling Interest	—	(11,845)	(27,425)	(43,191)	(25,038)
Net Income Attributable to CONSOL Energy Inc. Shareholders	$632,497	$346,781	$539,717	$442,470	$267,782
Earnings Per Share:					
Basic(B)	$2.79	$1.61	$2.99	$2.43	$1.47
Dilutive(B)	$2.76	$1.60	$2.95	$2.40	$1.45
Weighted Average Number of Common Shares Outstanding:					
Basic	226,680,369	214,920,561	180,693,243	182,386,011	182,050,627
Dilutive	229,003,599	217,037,804	182,821,136	184,679,592	184,149,751

Dividends Paid Per Share	$0.425	$0.400	$0.400	$0.400	$0.310

BALANCE SHEET DATA
(In thousands)

	December 31, 2011	2010	2009	2008	2007
Working (deficiency) capital	$509,580	$(549,779)	$(487,550)	$(527,926)	$(333,242)
Total assets	$12,525,700	$12,070,610	$7,775,401	$7,535,458	$6,333,490
Short-term debt	$—	$484,000	$522,850	$722,700	$372,900
Long-term debt (including current portion)	$3,198,114	$3,210,921	$468,302	$490,752	$507,208
Total deferred credits and other liabilities	$4,348,995	$4,283,674	$3,849,428	$3,716,021	$3,325,231
CONSOL Energy Inc. Stockholders' equity	$3,610,885	$2,944,477	$1,785,548	$1,462,187	$1,214,419

OTHER OPERATING DATA
(unaudited)

	Years Ended December 31, 2011	2010	2009	2008	2007
Coal:					
Tons sold (in thousands)(C)(D)	63,797	63,906	58,123	66,236	65,462
Tons produced (in thousands)(D)	62,574	62,352	59,389	65,077	64,617
Average sales price of tons produced ($ per ton produced)(D)	$72.72	$61.35	$58.28	$48.77	$40.60
Average production cost ($ per ton produced)(D)	$52.22	$46.55	$44.87	$41.08	$33.68
Recoverable coal reserves (tons in millions)(D)(E)	4,459	4,401	4,520	4,543	4,526
Number of active mining complexes (at end of period)	12	12	11	17	15
Gas:					
Net sales volumes produced (in billion cubic feet)(D)	153.5	127.9	94.4	76.6	58.3
Average sales price ($ per mcf)(D)(F)	$4.90	$5.83	$6.68	$8.99	$7.20
Average cost ($ per mcf)(D)	$3.86	$3.90	$3.44	$3.67	$3.33
Proved reserves (in billion cubic feet)(D)(G)	3,480	3,732	1,911	1,422	1,343

CASH FLOW STATEMENT DATA
(In thousands)

	For the Years Ended December 31, 2011	2010	2009	2008	2007
Net cash provided by operating activities	$1,527,606	$1,131,312	$1,060,451	$989,864	$558,633
Net cash used in investing activities(H)	$(578,524)	$(5,543,974)	$(845,341)	$(1,098,856)	$(972,104)
Net cash provided by (used in) financing activities	$(606,140)	$4,379,849	$(288,015)	$205,853	$231,239

OTHER FINANCIAL DATA
(Unaudited)
(In thousands)

	For the Years Ended December 31,				
	2011	2010	2009	2008	2007
Capital expenditures	$1,382,371	$1,154,024	$920,080	$1,061,669	$743,114
EBIT(I)	$1,159,285	$653,458	$786,520	$685,574	$421,978
EBITDA(I)	$1,777,682	$1,221,121	$1,223,937	$1,075,195	$746,693
Ratio of earnings to fixed charges(J)	3.53	2.74	11.76	10.67	7.48

(A) See Note 25–Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for sales and freight by operating segment.

(B) Basic earnings per share are computed using weighted average shares outstanding. Differences in the weighted average number of shares outstanding for purposes of computing dilutive earnings per share are due to the inclusion of the weighted average dilutive effect of employee and non-employee share-based compensation granted, totaling 2,323,230 shares, 2,117,243 shares, 2,127,893 shares, 2,293,581 shares, and 2,099,124 shares for the year ended December 31, 2011, 2010, 2009, 2008, and 2007, respectively.

(C) Includes sales of coal produced by CONSOL Energy and purchased from third parties. Of the tons sold, CONSOL Energy purchased the following amount from third parties: 0.6 million tons, 0.3 million tons, 0.3 million tons, 1.7 million tons and 0.5 million tons for the years ended December 31, 2011, 2010, 2009, 2008 and 2007, respectively.

(D) Amounts include intersegment transactions. For entities that are not wholly owned but in which CONSOL Energy owns an equity interest, includes a percentage of their net production, sales and reserves equal to CONSOL Energy's percentage equity ownership. For coal, the proportionate share of recoverable reserves for equity affiliates was 145, 172, 170, 171 and 179 tons at December 31, 2011, 2010, 2009, 2008 and 2007 respectively. Sales of coal produced by equity affiliates were 0.5 million tons, 0.6 million tons, 0.4 million tons, 0.2 million tons and 0.1 million tons for the years ended December 31, 2011, 2010, 2009, 2008 and 2007, respectively. For gas, amounts include 100% of CNX Gas' basis for all years presented; they exclude the noncontrolling interest reduction. There was no equity in affiliates at December 31, 2011, 2010, 2009 and 2008. The proportionate share of proved gas reserves for equity affiliates was 3.6 Bcfe at December 31, 2007. Sales of gas produced by equity affiliates were 0.32 Bcfe for the year ended December 31, 2007.

(E) Represents proven and probable coal reserves at period end.

(F) Represents average net sales price including the effect of derivative transactions.

(G) Represents proved developed and undeveloped gas reserves at period end.

(H) Net cash used in investing activities includes $485,464 related to the Noble transaction, $190,381 related to the Antero Transaction, and $54,099 related to the Hess Transaction in the year ended December 31, 2011. The year ended December 31, 2010 includes $3,470,212 and $991,034 related to the Dominion Acquisition and the purchase of CNX Gas Non-Controlling Interest, respectively. The year ended December 31, 2007 includes $296,724 related to the acquisition of AMVEST.

(I) EBIT is defined as earnings before deducting net interest expense (interest expense less interest income), income taxes, loss on debt extinguishment, and abandonment of long-lived assets. EBITDA is defined as earnings before deducting net interest expense (interest expense less interest income), income taxes and depreciation, depletion and amortization. Although EBIT and EBITDA are not measures of performance calculated in accordance with generally accepted accounting principles, management believes that they are useful to an investor in evaluating CONSOL Energy because they are widely used in the coal industry as measures to evaluate a company's operating performance before debt expense and cash flow. Financial covenants in our credit facility include ratios based on EBITDA. EBIT and EBITDA do not purport to represent cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance in accordance with generally accepted accounting principles. In addition, because EBIT and EBITDA are not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. Management's discretionary use of funds depicted by EBIT and EBITDA may be limited by working capital, debt service and capital expenditure requirements, and by restrictions related to legal requirements, commitments and uncertainties. A reconcilement of EBIT and EBITDA to financial net income is as follows:

	For the Years Ended December 31,				
	2011	2010	2009	2008	2007
Net Income	$632,497	$346,781	$539,717	$442,470	$267,782
Add: Interest expense	248,344	205,032	31,419	36,183	30,851
Less: Interest income	(8,919)	(7,642)	(5,052)	(2,363)	(12,792)
Less: Interest income included in black lung excise tax refund	—	—	(767)	(30,650)	—
Add: Income tax expense	155,456	109,287	221,203	239,934	136,137
Add: Loss on Debt Extinguishment	16,090	—	—	—	—
Add: Abandonment of Long-Lived Assets	115,817	—	—	—	—
Earnings before interest and taxes (EBIT)	1,159,285	653,458	786,520	685,574	421,978
Add: Depreciation, depletion and amortization	618,397	567,663	437,417	389,621	324,715
Earnings before interest, taxes and depreciation, depletion and amortization (EBITDA)	$1,777,682	$1,221,121	$1,223,937	$1,075,195	$746,693

(J) For purposes of computing the ratio of earnings to fixed charges, earnings represent income before income taxes plus fixed charges. Fixed charges include (a) interest on indebtedness (whether expensed or capitalized), (b) amortization of debt discounts and premiums and capitalized expenses related to indebtedness and (c) the portion of rent expense we believe to be representative of interest.

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

General

Fourth quarter demand for U.S. thermal and metallurgical coal continued to keep pace with the first three quarters of 2011. Demand for thermal coal from domestic electric generators decreased slightly from the previous year due to decreases in electricity demand and relatively low natural gas prices that have taken some market share from coal generation. International demand for U.S. coals, however, has exceeded any reduction in demand from domestic electric generators. Total U.S. coal exports are likely to exceed 100 million tons for 2011 which is at least 20 million tons higher than 2010 levels.

International demand for U.S. thermal coal slowed in the fourth quarter, but total 2011 thermal coal exports were almost double 2010 levels. Prices for spot coal delivered into Europe declined in the fourth quarter due to weak demand related to the economic slowdown and by weather conditions. Prices for export thermal coal remain competitive relative to U.S. thermal coal customers. Longer-term fundamentals for thermal coal exports to Europe remain favorable as subsidized mining in Europe is phased-out, nuclear growth plans are curtailed and South African coals are pulled into Asian markets.

Domestically, coal inventories at electric generators began to grow towards the end of the fourth quarter due to warmer than normal December weather and relatively low natural gas prices. U.S. electric demand during the fourth quarter of 2011 was estimated to be slightly lower than 2010 levels due to a relatively mild start to the winter season. Coal inventories at electric utilities in CONSOL Energy 's traditional markets grew slightly during the fourth quarter but remain below recent years.

Metallurgical coal demand for 2011 continued the strong pace set earlier this year as world blast furnace output grew an estimated 4.7% over 2010. Steel produced from the blast furnace method uses metallurgical coal and drives metallurgical coal demand. China continues to provide the bulk of the world's blast furnace iron production with almost 59% of world production, an increase of 6.3% compared to 2010. Although European steelmakers have shown signs of a slowdown, global production remains strong. In particular, production in the United States was up almost 13% compared to 2010, supported by a modest rebound in the North American auto sector.

Global supply of metallurgical coal began to normalize in the fourth quarter after conditions improved at Australian mines impacted by the Spring 2011 flooding. International settlement prices have declined since the temporary supply and demand imbalance was resolved, but currently reflect the tight global supply and demand balance for metallurgical coal. CONSOL Energy is well positioned to take advantage of this market with its low cost Buchanan low-volatile operation, low cost high-volatile operations in Northern Appalachia and mid-vol operations set to open in early 2012.

Natural gas markets enjoyed record demand in 2011 primarily driven by gas fired electric generation and an increase in industrial consumption. Some of this increase in demand came from electric generators taking advantage of relatively low prices and utilized more natural gas generation. Supply however, has continued to grow at very strong rates due to the abundance of new shale resources. This supply and demand imbalance is tempered by decreased imports of liquefied natural gas (LNG) and Western Canadian pipeline gas, as well as increased exports to Eastern Canada and Mexico. This supply response may not be sufficient to bring the markets into balance and additional downward price pressures could be experienced in 2012.

Longer-term rebalancing will be aided by declining conventional production and the shift in drilling towards oil and “liquids rich” gas plays. The widespread perception that shale gas production will yield lower and less volatile natural gas prices could spur additional demand as electric generators choose to build additional high-efficiency baseload gas power plants. Additional demand will come from the petrochemical industry and developing sources of demand such as more wide-scale use of natural gas vehicles. CONSOL Energy continues to believe that natural gas will bring balance to CONSOL Energy's portfolio of long-lived energy resources.

A failure to return to normal weather patterns could have a negative short-term impact on CONSOL Energy's natural gas and domestic thermal coal demand. Additionally, uncertainty in the short term economic outlook could lead to a slowing of global economic expansion. Economic uncertainty is currently driven by the European sovereign debt crisis, lingering high U.S. unemployment rates and instability in the Middle East oil-producing region. The fundamental long-term drivers of CONSOL Energy's business remain unchanged as the global demand for low-cost, reliable sources of energy and metallurgical coal remain strong in both the developed and developing world.
CONSOL Energy engaged in several business and financing transactions in the year ended December 31, 2011. These transactions include the following:

- On October 27, 2011, CONSOL Energy's Board of Directors increased the regular annual dividend by 25%, or $0.10 per share, to $0.50 per share.

- On October 21, 2011, CNX Gas Company LLC (CNX Gas Company) completed a sale to a subsidiary of Hess Corporation (Hess) of 50% of its nearly 200 thousand net Utica Shale acres in Ohio. Cash proceeds related to this transaction were $54 million, which is net of $5 million of transaction fees. Additionally, CONSOL Energy and Hess entered into a joint development agreement pursuant to which Hess agreed to pay approximately $534 million in the form of a 50% drilling carry of certain CONSOL Energy working interest obligations as the acreage is developed. The net gain on the transaction was $53 million and was recognized in the Consolidated Statements of Income as Other Income.

- On September 30, 2011, CNX Gas Company completed a sale to Noble Energy, Inc. (Noble) of 50% of the Company's undivided interest in certain Marcellus Shale oil and gas properties in West Virginia and Pennsylvania covering approximately 628 thousand net acres and 50% of the Company's undivided interest in certain of its existing Marcellus Shale wells and related leases. Cash proceeds of $485 million were received related to this transaction, which are net of $35 million transaction fees. Additionally, a note receivable has been recognized related to the two additional cash payments to be received on the first and a second anniversary of the transaction closing date. The discounted notes receivable of $312 million and $296 million have been recorded in Accounts and Notes Receivables-Notes Receivable and Other Assets-Notes Receivable, respectively. Subsequent to the transaction, an additional receivable of $17 million and a payable of approximately $980 thousand were recorded for closing adjustments and have been included in Accounts and Notes Receivable - Other and Accounts Payable, respectively. The net loss on the transaction was $64 million and was recognized in the Consolidated Statements of Income as Other Income. As part of the transaction, CNX Gas Company also received a commitment from Noble to pay one-third of the Company's working interest share of certain drilling and completion costs, up to approximately $2.1 billion with certain restrictions. These restrictions include the suspension of carry if average natural gas Henry Hub prices are below $4.00 per million British thermal units (MMBtu) for three consecutive months. The carry will remain suspended until average natural gas prices are above $4.00/MMBtu for three consecutive months. Restrictions also include a $400 million annual maximum on Noble's carried cost obligation.

- On September 30 2011, CNX Gas Company and Noble formed CONE Gathering LLC (CONE), a joint venture established to develop and operate each company's gas gathering system needs in the Marcellus Shale play. CNX Gas Company's 50% ownership interest in CONE is accounted for under the equity method of accounting. CNX Gas contributed its existing Marcellus Shale gathering infrastructure which had a net book value of $120 million and Noble contributed cash of approximately $68 million. CONE made a cash distribution to CNX Gas in the amount of $68 million. The cash proceeds have been recorded as cash inflows of $60 million and $8 million in Distributions from Equity Affiliates and Proceeds from the Sale of Assets, respectively, on the Consolidated Statements of Cash Flow. The gain on the transaction was $7 million and was recognized in the Consolidated Statements of Income as Other Income.

- On September 21, 2011 CONSOL Energy entered into an agreement with Antero Resources Appalachian Corp. (Antero), pursuant to which CONSOL Energy assigned to Antero overriding royalty interests (ORRI) of approximately 7% in approximately 116 thousand net acres of Marcellus Shale located in nine counties in southwestern Pennsylvania and north central West Virginia, in exchange for $193 million. The net gain of $41 million is included in Other Income in the Consolidated Statements of Income.

- CONSOL Energy incurred costs of approximately $15 million in the year ended December 31, 2011 related to the solicitation of consents from the holders of CONSOL Energy's outstanding 8.00% Senior Notes due 2017, 8.25% Senior Notes due 2020 and 6.375% Senior Notes due 2021. The consents allowed an amendment to the indentures for each of those notes, clarifying that the transactions such as those contemplated by the August 2011 Asset Acquisition Agreements with Noble and Hess were permissible under those indentures.

- In June 2011, the Bituminous Coal Operators Association (BCOA) and the United Mine Workers of America (UMWA) reached a new collective bargaining agreement which will run from July 1, 2011 to December 31, 2016. That agreement, the National Bituminous Coal Wage Agreement of 2011 (2011 NBCWA), covers approximately 2,900 employees of CONSOL Energy subsidiaries. The 2011 NBCWA is the successor agreement to the 2007 NBCWA that was set to expire on December 31, 2011. Key elements of the new agreement include the following items:

a. A wage increase of $1.00 per hour effective July 1, 2011, and an additional $1.00 per hour increase each January 1st throughout the contract term.
b. Contributions to the 1974 Pension Plan, a multi-employer plan, will continue at the current rate of $5.50 per hour throughout the contract term. New inexperienced miners hired after December 31, 2011 will not participate in the 1974 Pension Plan, but will receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014-2016) to the UMWA Cash Deferred Savings Plan (CDSP), which is a 401(k) Plan. UMWA represented employees with over 20 years of credited service under the 1974 Pension Plan will receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014-2016) to the CDSP beginning January 1, 2012. Also beginning January 1, 2012, UMWA represented employees will have the right to elect to opt-out of future participation in the 1974 Pension Plan and upon such election, will receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014 - 2016) to the CDSP.
c. A $1.50 per hour contribution starting January 1, 2012 to a new defined contribution plan to provide retiree bonus payments to eligible retirees in 2014, 2015 and 2016.
d. An increased contribution from $0.50 per hour to $1.10 per hour effective January 1, 2012 to the 1993 Benefit Plan, which is a defined contribution plan providing health benefits to certain retirees.
e. Various other changes related to absenteeism, contributions to various UMWA benefit funds, eligibility for various vacation days and sick days.

- In June 2011, CONSOL Energy management decided to permanently idle its Mine 84 underground facility. This facility had been on idle status since March 2009. Various options for the facility were explored, such as selling and operating with continuous miners, but management decided it was in the best interest of the Company to abandon the underground workings of this facility and reallocate resources into more profitable coal operations and Marcellus Shale drilling operations. The Company redeployed all of the movable equipment from the mine that could be used at other locations. The abandonment of this underground facility resulted in a $116 million charge to pre-tax earnings. See Note 10—Property, Plant and Equipment in the Notes to the Audited Consolidated Financial Statements included in Item 8 of this Form 10-K for additional disclosure. The Company expects the closure of Mine 84 to result in pre-tax cash savings of $18 million per year.

• In April 2011, CNX Gas entered into an amendment to its senior secured credit agreement which increases the availability under the agreement from $700 million to $1.0 billion, decreases the interest rate and extends the term from May 6, 2014 to April 12, 2016. The amended credit agreement continues to be secured by substantially all of the assets of CNX Gas and its subsidiaries.

- In April 2011, CONSOL Energy amended and extended its existing $1.5 billion senior secured credit agreement, which decreases the interest rate and extends the term from May 7, 2014 to April 12, 2016. The amended agreement continues to be secured by substantially all of the assets of CONSOL Energy and certain of its subsidiaries.

- On March 9, 2011, CONSOL Energy issued $250 million of 6.375% senior notes due March 2021. The Notes are guaranteed by substantially all of the Company's existing and future wholly owned domestic restricted subsidiaries. The Company issued the Notes with the intention of using the net proceeds to repay its outstanding 7.875% senior secured notes due March 1, 2012, on or before their maturity. On April 11, 2011, CONSOL Energy redeemed all of its outstanding $250 million, 7.875% senior secured notes due March 1, 2012 in accordance with the terms of the indenture governing the notes. By using the proceeds of the $250 million, 6.375% senior notes due March 2021 to effect this redemption, the Company effectively extended the maturity of the $250 million of long-term indebtedness by nine years at a lower interest rate. The redemption price included principal of $250 million, a make-whole premium of $16 million and accrued interest of $2 million, for a total redemption cost of approximately $268 million. The loss on extinguishment of debt was approximately $16 million, which primarily represents the interest that would have been paid on these notes if they had been held to maturity.

CONSOL Energy is managing several significant matters that may affect our business and impact our financial results in the future including the following:

- Challenges in the overall environment in which we operate create increased risks that we must continuously monitor and manage. These risks include (i) increased prices for commodities such as diesel fuel, synthetic rubber and steel that we use in our operations and (ii) increased scrutiny of existing safety regulations and the development of new safety regulations.

- Federal and state environmental regulators are reviewing our operations more closely and more strictly interpreting and enforcing existing environmental laws and regulations, resulting in increased costs and delays. For example, we entered into a consent decree with the U.S. Environmental Protection Agency and the West Virginia Department of Environmental Protection pursuant to which we agreed to construct an advanced technology mine water treatment plant and related facilities to reduce high levels of total dissolved solids in water discharges from certain of our mines in Northern West Virginia, at a total estimated cost of approximately $200 million.

- Federal and state regulators have proposed regulations which, if adopted, would adversely impact our business. These proposed regulations could require significant changes in the manner in which we operate and/or would increase the cost of our operations. For example, the Department of Interior, Office of Surface Mining Reclamation and Enforcement (OSM) is currently preparing an environmental impact statement relating to OSM's consideration of five alternatives for amending its coal mining stream protection rules. All of the alternatives, except the no action alternative, could make it more costly to mine our coal and/or could eliminate the ability to mine some of our coal. Further, other regulations would make it more expensive for our customers to operate their businesses, possibly inducing them to move to alternative fuel sources. For example, the EPA has issued a proposed rule that would regulate coal combustion residuals from coal fired electric generating facilities under the federal Resource Conservation and Recovery Act (RCRA) as either a hazardous waste under Subtitle C of RCRA or as a non-hazardous waste under Subtitle D of RCRA. If final rules are adopted consistent with either of the proposed alternatives, the cost of handling and disposal of coal combustion residuals could increase making it more expensive to generate electricity from coal. Another example is the Cross-State Air Pollution Rule (CSAPR) that was finalized by the EPA on July 6, 2011, although the effective date of the rule has been stayed by a court. CSAPR replaces the Clean Air Interstate Rule and regulates the amount of SO_2 and NO_x that power plants in 23 eastern states can emit in order to meet clean air requirements in downwind states. Another example is the Mercury and Air Toxic Standards issued by the EPA on December 16, 2011. The new regulations, which will be published in February 2012, set mercury and air toxic standards for new and existing coal and oil fired electric utility steam generating units and include more stringent new source performance standards (NSPS) for particulate matter (PM), SO_2 and NO_X. Some older coal fired power plants may be retired or have operation time reduced rather than install additional expensive emission controls which could reduce the amount of coal consumed.

- On April 19, 2011, the Pennsylvania Department of Environmental Protection announced its intent to not renew permits for publicly owned treatment works (POTW) that treat municipal wastewater to accept wastewater from

Marcellus Shale operators. They called on operators to cease delivering wastewater to the POTWs by May 19, 2011. CONSOL Energy has implemented a re-cycle and re-use process of its Marcellus derived water for hydraulic fracturing operations, and will only safely dispose of Marcellus wastewater in regulated, underground injection control wells.

- CONSOL Energy continues to explore potential sales of non-core assets.

Results of Operations
Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $632 million, or $2.76 per diluted share, for the year ended December 31, 2011. Net income attributable to CONSOL Energy shareholders was $347 million, or $1.60 per diluted share, for the year ended December 31, 2010.
The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $933 million of earnings before income tax for the year ended December 31, 2011 compared to $536 million for the year ended December 31, 2010. The total coal division sold 62.7 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, for the year ended December 31, 2011 compared to 63.0 million tons for the year ended December 31, 2010.
The average sales price and average costs per ton for all active coal operations were as follows:

	For the Years Ended December 31,				
	2011	2010	Variance	Percent Change	
Average Sales Price per ton sold	$ 72.25	$ 61.33	$ 10.92	17.8	%
Average Costs per ton sold	52.08	46.78	5.30	11.3	%
Margin	$ 20.17	$ 14.55	$ 5.62	38.6	%

The higher average sales price per ton sold reflects successful re-negotiation of several domestic thermal contracts whose pricing took effect January 1, 2011, another strong quarter of high volatile metallurgical coal sales and demand for our premium low volatile metallurgical coal. Also, 11.7 million tons were priced on the export market at an average sales price of $121.29 per ton for the year ended December 31, 2011 compared to 8.1 million tons at an average price of $97.10 per ton for the year ended December 31, 2010.

Average costs per ton sold increased $5.30 per ton in the period-to-period comparison due primarily to the following:

- Operating supplies and maintenance costs per ton sold were higher due to increased equipment overhauls, additional roof control and additional equipment maintenance.
- Depreciation, depletion and amortization increased due to additional assets placed into service after the 2010 period.
- Labor and labor related charges increased as a result of additional employees, increased overtime hours worked and the impact of the $1.50 per hour worked UMWA contract wage increases, $0.50 per hour worked related to the prior UMWA contract and $1.00 per hour worked related to the July 2011 UMWA contract.
- Other post employment benefits and pension expenses increased primarily due to changes in discount rates, employees retiring sooner than originally anticipated and higher average claim costs.
- Royalties and production related taxes increased due to higher sales price of coal sold.

The total gas division includes coalbed methane (CBM), shallow oil and gas, Marcellus and other gas. The total gas division contributed $130 million of earnings before income tax for the year ended December 31, 2011 compared to $180 million for the year ended December 31, 2010. Total gas production was 153.5 billion net cubic feet for the year ended December 31, 2011 compared to 127.9 billion net cubic feet for the year ended December 31, 2010. Total gas production increased primarily due to the on-going drilling program partially offset by 6.6 billion net cubic feet of production related to the Noble joint venture.

The average sales price and average costs for all active gas operations were as follows:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$4.90	$5.83	$(0.93)	(16.0)%
Average Costs per thousand cubic feet sold	3.86	3.90	(0.04)	(1.0)%
Margin	$1.04	$1.93	$(0.89)	(46.1)%

Total gas division outside sales revenues were $752 million for the year ended December 31, 2011 compared to $746 million for the year ended December 31, 2010. The increase was primarily due to 20.0% increase in volumes sold partially offset by the 16.0% reduction in average price per thousand cubic feet sold. The volume increase was primarily due to additional wells drilled under the on-going drilling program, and additional volumes from the wells purchased in the Dominion Acquisition, which occurred on April 30, 2010 offset, in part, by the impact of the Noble joint venture which reduced 2011 volumes by approximately 6.6 billion net cubic feet. The decrease in average sales price is the result of various gas swap transactions that occurred throughout both periods and lower average market prices. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 84.0 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2011 at an average price of $5.21 per thousand cubic feet. These financial hedges represented 52.1 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2010 at an average price of $7.66 per thousand cubic feet.

Total gas unit costs decreased slightly for the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to lower depreciation, depletion and amortization and lower gathering costs partially offset by increased lifting costs. The wells purchased in the Dominion Acquisition increased total operating costs by $0.32 per thousand cubic feet due to higher costs and lower volumes produced related to the age of these wells compared to the legacy CONSOL Energy wells. Excluding the impact of these purchased wells, unit costs improved $0.36 per thousand cubic feet primarily due to the additional volumes produced, improved depreciation, depletion and amortization and lower gathering charges. Volumes increased in the period-to-period comparison due to the on-going drilling program and the additional volumes from the wells purchased in the Dominion Acquisition partially offset by the impact of the Noble joint venture. Lower depreciation, depletion and amortization rates were the result of additional gas reserves recognized at December 31, 2010. Gathering and compression charges were improved primarily due to a fuel surcharge reduction by a utility provider. Lifting costs increased in the period-to-period comparison due to additional well services to maintain production levels.

The other segment includes industrial supplies activity, terminal, river and dock service activity, income taxes and other business activities not assigned to the coal or gas segment.

Included in both coal and gas unit costs are Selling, General and Administrative Expenses and total Company long-term liabilities, such as other post employment benefits (OPEB), the salary retirement plan, workers' compensation and long-term disability. Total Company Selling, General and Administrative Expenses are allocated to various segments primarily based on revenue and capital expenditure projections between coal and gas as a percent of total. Total Company Selling, General and Administrative Expenses were made up of the following items:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Employee wages and related expenses	$80	$72	$8	11.1%
Demurrage	6	2	4	200.0%
Advertising and promotion	10	7	3	42.9%
Contributions	7	4	3	75.0%
Commissions	14	12	2	16.7%
Consulting and professional services	28	26	2	7.7%
Miscellaneous	31	27	4	14.8%

Total Company Selling, General and Administrative Expenses	$176	$150	$26	17.3 %

Total Company Selling, General and Administrative Expenses increased due to the following:

- Employee wages and related expenses increased $8 million which was primarily attributable to the support staff retained in the Dominion Acquisition and additional hiring of support staff in the period-to-period comparison.
- Demurrage charges were higher in the 2011 period due to increased export traffic at the Baltimore terminal.
- Advertising and promotion expense increased $3 million in the period-to-period comparison due to additional campaigns initiated in the 2011 period.
- Contributions expense increased $3 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Commission expense increased $2 million due to the increase in average sales price and additional tons sold for which a third party was owed a commission in the period-to-period comparison.
- Consulting and professional services increased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Miscellaneous selling, general and administrative expenses increased $4 million due to various transactions that occurred throughout both periods, none of which were individually material.

Total Company long-term liabilities, such as other post employment benefits (OPEB), the salary retirement plan, workers' compensation and long-term disability are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Total CONSOL Energy expense related to our actuarial calculated liabilities was $332 million for the year ended December 31, 2011 compared to $287 million for the year ended December 31, 2010. The increase of $45 million was due primarily to OPEB and salary pension expense. The additional OPEB and salary pension expense related to changes in discount rates, employees retiring sooner than originally anticipated and higher average claim costs. See Note 15—Pension and Other Postretirement Benefit Plans and Note 16—Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-k for additional details related to total Company expense increases.

TOTAL COAL SEGMENT ANALYSIS for the year ended December 31, 2011 compared to the year ended December 31, 2010:

The coal segment contributed $933 million of earnings before income tax in the year ended December 31, 2011 compared to $536 million in the year ended December 31, 2010. Variances by the individual coal segments are discussed below.

	For the Year Ended December 31, 2011					Difference to Year Ended December 31, 2010				
	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$3,058	$368	$1,072	$27	$4,525	$57	$196	$392	$15	$660
Purchased Coal	—	—	—	42	42	—	—	—	8	8
Total Outside Sales	3,058	368	1,072	69	4,567	57	196	392	23	668
Freight Revenue	—	—	—	232	232	—	—	—	106	106
Other Income	6	11	—	62	79	(2)	4	—	14	16
Total Revenue and Other Income	3,064	379	1,072	363	4,878	55	200	392	143	790
Costs and Expenses:										
Total operating costs	1,919	175	288	200	2,582	(15)	106	56	(7)	140
Total provisions	220	20	38	54	332	22	13	11	(74)	(28)
Total selling, administrative & other costs	167	18	28	87	300	25	13	10	(14)	34
Depreciation, depletion and amortization	302	31	37	130	500	28	20	16	78	142
Total Costs and Expenses	2,608	244	391	471	3,714	60	152	93	(17)	288
Freight Expense	—	—	—	231	231	—	—	—	105	105
Total Costs	2,608	244	391	702	3,945	60	152	93	88	393
Earnings (Loss) Before Income Taxes	$456	$135	$681	$(339)	$933	$(5)	$48	$299	$55	$397

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THERMAL COAL SEGMENT

The thermal coal segment contributed $456 million to total Company earnings before income tax for the year ended December 31, 2011 compared to $461 million for the year ended December 31, 2010. The thermal coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Produced Thermal Tons Sold (in millions)	52.0	55.8	(3.8)	(6.8)%
Average Sales Price Per Thermal Ton Sold	$58.87	$53.76	$5.11	9.5 %
Average Operating Costs Per Thermal Ton Sold	$36.93	$34.64	$2.29	6.6 %
Average Provision Costs Per Thermal Ton Sold	$4.24	$3.55	$0.69	19.4 %
Average Selling, Administrative and Other Costs Per Thermal Ton Sold	$3.21	$2.55	$0.66	25.9 %
Average Depreciation, Depletion and Amortization Costs Per Thermal Ton Sold	$5.81	$4.90	$0.91	18.6 %
Total Average Costs Per Thermal Ton Sold	$50.19	$45.64	$4.55	10.0 %
Margin Per Thermal Ton Sold	$8.68	$8.12	$0.56	6.9 %

Thermal coal revenue was $3,058 million for the year ended December 31, 2011 compared to $3,001 million for the year ended December 31, 2010. The $57 million increase was attributable to a $5.11 per ton higher average sales price partially offset by 3.8 million fewer tons sold in 2011. The higher average thermal coal sales price in the 2011 period was the result of the successful re-negotiation of several domestic thermal contracts whose pricing took effect on January 1, 2011. Also, 2.8 million tons of thermal coal was priced on the export market at an average sales price of $66.45 per ton for the year ended December 31, 2011 compared to 2.4 million tons at an average price of $54.68 per ton for year ended December 31, 2010. The thermal coal segment was also impacted by 4.7 million tons of thermal coal sold on the high volatile metallurgical coal market for the year ended December 31, 2011, which was 2.3 million tons more than the tons sold in the year ended December 31, 2010.

Other income attributable to the thermal coal segment represents earnings from our equity affiliates that operate thermal coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Operating costs are comprised of labor, supplies, maintenance, subsidence, taxes other than income and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the thermal coal segment were $1,919 million for the year ended December 31, 2011 compared to $1,934 million for the year ended December 31, 2010. Operating costs related to the thermal coal segment decreased primarily due to lower volumes sold partially offset by higher average costs per ton sold.

Changes in the average operating costs per ton for thermal coal sold were also related to the following items:

- Average operating supplies and maintenance costs per thermal ton sold increased due to additional maintenance and equipment overhaul costs, additional roof control costs, and increased fuel and lubricants. Additional maintenance and equipment overhaul costs are related to additional equipment being serviced in the current period. Additional roof control costs resulted from changes in roof support strategy, such as using longer roof bolts and additional types of roof support, in order to improve the safety of our mines and to provide a more reliable source of production for our customers. Increased fuel and lubricant costs are related to higher fuel prices in the current period.
- Labor and related benefits were impaired on a cost per thermal ton sold basis due to higher costs and lower volumes sold. Higher benefit costs were due primarily to contributions made to the 1974 Pension Trust (the Trust), which is a multiemployer pension plan. Contributions to the Trust were negotiated under the National Bituminous Coal Wage Agreement and are based on a rate per hour worked by members of the United Mine Workers of America (UMWA). The contribution rate increased $0.50 per hour worked in the 2011 period compared to the 2010 period. Non-represented benefit rates for active employees also increased as a result of continued increases in healthcare

costs. Labor and related benefits also increased due to additional employees and the impact of the wage increases of $1.50 per hour worked, $0.50 per hour worked effective January 1, 2011 under the previous collective bargaining agreement and $1.00 per hour worked effective July 1, 2011 related to the July 2011 collective bargaining agreement. These increases were offset, in part, as a result of the Tax Relief and Health Care Act of 2006 authorizing general fund revenues and expanding transfers of interest from the Abandoned Mine Land trust fund to cover orphan retirees which remain in the Combined Fund, the 1992 Benefit Plan and the 1993 Plan. The additional federal funding eliminated the 2011 funding of orphan retirees by participating active employers of the plans, resulting in lower expense in the period-to-period comparison. The additional federal funding does not impact the amount of contributions required to be paid for our assigned retirees. Also, we may be required to make additional payments in the future to these plans in the event the federal contributions are not sufficient to cover the benefits.

- Production taxes average cost per thermal ton sold increased primarily due to the $5.11 per ton higher average sales price.
- Average operating costs per thermal ton sold increased due to lower tons sold resulting in fixed costs being allocated over less tons resulting in higher unit costs.

Provision costs are made up of the expenses related to the Company's long-term liabilities, such as other post employment benefits (OPEB), the salary retirement plan, workers' compensation, long-term disability and accretion on mine closing and related liabilities. With the exception of accretion expense on mine closing and related liabilities, these liabilities are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Accretion is calculated on a mine-by-mine basis. Provision costs attributable to the thermal coal segment were $220 million for the year ended December 31, 2011 compared to $198 million for the year ended December 31, 2010. The increased thermal coal provision expense was attributable to the total Company increase in long-term liability expense discussed in the total Company results of operations section. Thermal coal accretion expense related to mine closing and related liabilities remained consistent in the period-to-period comparison.

Selling, administrative and other costs attributable to the thermal coal segment include selling, general and administrative expenses and direct administrative costs. Selling, general and administrative costs, excluding commission expense, are allocated to various segments based on a combination of estimated time worked by various support groups and operating costs incurred at the mine. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative costs are associated directly with the coal division of the business and are allocated to various mines based on a combination of estimated time worked and production. Selling, administrative and other costs related to the thermal coal segment were $167 million for the year ended December 31, 2011 compared to $142 million for the year ended December 31, 2010. The cost increases attributable to the thermal coal segment were attributable to higher selling, general and administrative expenses as discussed in the total Company results of operations section and higher direct administrative costs. Higher direct administrative costs were primarily due to higher employee related expenses due to additional support staff requirements, increased safety reward expense and increased coal sampling charges in the period-to-period comparison. These higher costs and lower sales volumes resulted in a $0.66 per ton increase in average cost per ton sold.

Depreciation, depletion and amortization for the thermal coal segment was $302 million for the year ended December 31, 2011 compared to $274 million for the year ended December 31, 2010. The increase was primarily due to additional equipment and infrastructure placed into service after the 2010 period that was depreciated on a straight-line basis. The increase was also due to higher units-of-production rates for thermal coal mines due to additional air shafts being placed into service after the 2010 period which had higher unit rates than historical shafts put into service. These higher expenses and lower sales tons, resulted in a $0.91 increase in average costs per ton sold.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $135 million to total Company earnings before income tax for the year ended December 31, 2011 compared to $87 million for the year ended December 31, 2010. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Produced High Vol Met Tons Sold (in millions)	4.7	2.4	2.3	95.8 %
Average Sales Price Per High Vol Met Ton Sold	$78.06	$72.89	$5.17	7.1 %
Average Operating Costs Per High Vol Met Ton Sold	$37.18	$29.16	$8.02	27.5 %
Average Provision Costs Per High Vol Met Ton Sold	$4.17	$3.08	$1.09	35.4 %
Average Selling, Administrative and Other Costs Per High Vol Met Ton Sold	$3.79	$2.26	$1.53	67.7 %
Average Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Sold	$6.50	$4.61	$1.89	41.0 %
Total Average Costs Per High Vol Met Ton Sold	$51.64	$39.11	$12.53	32.0 %
Margin Per High Vol Met Ton Sold	$26.42	$33.78	$(7.36)	(21.8 %)

High volatile metallurgical coal revenue was $368 million for the year ended December 31, 2011 compared to $172 million for the year ended December 31, 2010. Strength in the metallurgical coal market has continued to allow the export of Northern Appalachian coal, historically sold domestically on the thermal coal market, to crossover to the Brazilian and Asian metallurgical coal markets. Also, 4.3 million tons of thermal coal was priced on the export market at an average sales price of $77.48 per ton for the year ended December 31, 2011 compared to 2.3 million tons at an average price of $73.51 per ton for year ended December 31, 2010. As a result, average sales prices for high volatile metallurgical coal have increased due to growing the base of end user customers.

Other income attributed to the high volatile metallurgical coal segment represents earnings from our equity affiliates that operate high volatile metallurgical coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Operating costs related to the high volatile metallurgical coal segment were $175 million for the year ended December 31, 2011 compared to $69 million for the year ended December 31, 2010. Operating costs related to the high volatile metallurgical coal segment increased primarily due to higher volumes sold and higher average costs per ton sold. Changes in average operating costs per ton for high volatile metallurgical coal sold were primarily related to the following items:

- Average operating costs per high volatile metallurgical ton sold increased due to the mix of mines selling coal on the high volatile metallurgical coal market. As higher cost structure mines sell coal in the high volatile metallurgical market, average operating costs per ton sold increase. Previously, this segment only included lower cost structure mines.
- Labor and related benefits increased due to higher employee counts, higher non-represented benefit rates and higher contributions per hour worked to the 1974 Pension Trust (Trust). Labor and related benefits increased due to additional employees in the period-to-period comparison. Higher labor and related costs were also due to higher non-represented benefit rates for active employees related to the continued increase in healthcare costs. Higher contributions made to the Trust were discussed in the thermal coal segment. Labor and related benefits also increased due to the impact of the wage increases of $1.50 per hour worked, $0.50 per hour worked effective January 1, 2011 under the previous collective bargaining agreement and $1.00 per hour worked effective July 1, 2011 related to the July 2011 collective bargaining agreement, in the period-to-period comparison. These increases were offset by lower overall contributions to certain multiemployer benefit plans such as the 1992 Fund, the 1993 Fund and the Combined Fund, which were also discussed in the thermal coal segment. Increased labor and related benefit costs per unit sold were also offset, in part, by additional volumes of high volatile metallurgical tons sold in the period-to-period

comparison.

- Average operating supplies and maintenance costs per high volatile metallurgical ton sold increased due to additional maintenance and equipment overhaul costs, additional roof control costs, and increased fuel and lubricants. Additional maintenance and equipment overhaul costs are related to additional equipment being serviced in the current period. Additional roof control costs resulted from changes in roof support strategy, such as using longer roof bolts and additional types of roof support, in order to improve the safety of our mines and to provide a more reliable source of production for our customers.

- Average coal preparation costs per high vol ton sold increased due to additional maintenance projects that have been completed at our preparation plants in the period-to-period comparison.
- Production taxes average cost per high volatile metallurgical ton sold increased due to the $5.17 per ton higher average sales price.
- In-transit charges average cost per high volatile metallurgical ton sold increased primarily due to the increased cost of moving coal from the mine to the preparation plant for processing. This increase is primarily related to the mix of mines now shipping high volatile metallurgical coal.

The provision expense attributable to the high volatile metallurgical coal segment was $20 million for the year ended December 31, 2011 compared to $7 million for the year ended December 31, 2010. The increase in the high volatile metallurgical coal provision expense was attributable to the total Company increased long-term liability expense discussed in the total Company results of operations section. The per unit impairment was offset, in part, by additional tons sold in the period-to-period comparison. Also, high volatile metallurgical coal accretion expense related to mine closing and related liabilities remained consistent in the period-to-period comparison which offset some increases in costs per ton sold.

Selling, administrative and other costs attributable to the high volatile metallurgical coal segment include selling, general and administrative expenses and direct administrative costs. Selling, general and administrative expenses, excluding commission expense, are allocated to various segments based on a combination of estimated time worked by various support groups and operating costs incurred at the mine. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative costs are associated directly with the coal division of the business and are allocated to various mines based on a combination of estimated time worked and production. Selling, administrative and other costs related to the high volatile metallurgical coal segment were $18 million for the year ended December 31, 2011 compared to $5 million for the year ended December 31, 2010. The cost increase attributable to the high volatile metallurgical coal segment is attributable to higher total Company selling, general and administrative expenses as discussed in the total Company results of operations section and higher direct administrative costs. Higher direct administrative costs were primarily due to higher employee related expenses due to additional support staff requirements, increased safety reward expense and increased coal sampling charges in the period-to-period comparison. These additional expenses increased unit costs per ton sold and were offset, in part, by higher volumes of high volatile metallurgical coal sold.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $31 million for the year ended December 31, 2011 compared to $11 million for the year ended December 31, 2010. The increase was primarily due to additional equipment and infrastructure placed into service after the 2010 period that is depreciated on a straight-line basis. The increase was also due to higher units-of-production rates for high volatile metallurgical coal mines related to additional air shafts being placed into service after the 2010 period which had higher unit rates than historical shafts put into service. These increases in unit costs per ton sold were offset, in part, by additional high volatile metallurgical tons sold which lowered the unit cost per ton impact.

The high volatile metallurgical coal segment increased the margin on our coal production that would have otherwise been sold in the domestic thermal coal market.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $681 million to total Company earnings before income tax in the year ended December 31, 2011 compared to $382 million in the year ended December 31, 2010. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Years Ended December 31,				
	2011	2010	Variance	Percent Change	
Produced Low Vol Met Tons Sold (in millions)	5.6	4.6	1.0	21.7	%
Average Sales Price Per Low Vol Met Ton Sold	$ 191.81	$ 146.32	$ 45.49	31.1	%
Average Operating Costs Per Low Vol Met Ton Sold	$ 51.57	$ 49.82	$ 1.75	3.5	%
Average Provision Costs Per Low Vol Met Ton Sold	$ 6.84	$ 5.90	$ 0.94	15.9	%
Average Selling, Administrative and Other Costs Per Low Vol Met Ton Sold	$ 4.97	$ 3.95	$ 1.02	25.8	%
Average Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Sold	$ 6.62	$ 4.57	$ 2.05	44.9	%
Total Average Costs Per Low Vol Met Ton Sold	$ 70.00	$ 64.24	$ 5.76	9.0	%
Margin Per Low Vol Met Ton Sold	$ 121.81	$ 82.08	$ 39.73	48.4	%

Low volatile metallurgical coal revenue was $1,072 million for the year ended December 31, 2011 compared to $680 million for the year ended December 31, 2010. The $392 million increase was attributable to a $45.49 per ton higher average sales price due to the strength of the low volatile metallurgical market, both domestic and foreign. The strength of these markets is related to continued worldwide demand for premium low volatile metallurgical coal. For the 2011 period, 4.6 million tons of low volatile metallurgical coal was priced on the export market at an average price of $196.46 per ton compared to 3.3 million tons at an average price of $144.23 per ton for the 2010 period.

Operating costs are made up of labor, supplies, maintenance, subsidence, taxes other than income and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the low volatile metallurgical coal segment were $288 million for the year ended December 31, 2011 compared to $232 million for the year ended December 31, 2010. Operating costs related to the low volatile metallurgical coal segment increased primarily due to higher volumes sold.

Changes in the average operating costs per ton for low volatile metallurgical coal sold were primarily related to the following items:

- Production taxes average cost per low volatile metallurgical ton sold increased due to the $45.49 per ton higher average sales price.
- Average operating supplies and maintenance costs per low volatile metallurgical ton sold increased due to additional roof control costs, additional ventilation costs of coalbed methane gas, additional equipment overhaul costs and increased rock dusting. Additional roof control costs resulted from changes in roof support strategy, such as types of roof support used and quantity of supports put into place. The roof control strategy was changed to improve the safety of the mine and to provide a more reliable source of production for our customers. Roof control costs also increased due to higher steel prices in the period-to-period comparison. In addition, costs were incurred in the 2011 period to increase the number of bore holes that were placed ahead of mining to ventilate the coalbed methane gas from the mine. Additional maintenance and equipment overhaul costs are related to additional equipment being serviced in the current period. Increased rock dusting was primarily due to changes in regulations.

These increases in costs were partially offset by the following items:

- Coal inventory volumes increased slightly at December 31, 2011 compared to December 31, 2010 and carrying value increased $5.09 per ton in the corresponding period. Coal inventory decreased 0.2 million tons at December 31, 2010 compared to December 31, 2009 and the carrying value of the inventory during the corresponding period increased $7.29 per ton. These changes in inventory caused a reduction in average operating cost per ton sold in the period-to-period comparison.

- Power costs per low volatile metallurgical ton sold were improved due to utility rate reductions that became effective in the 2011 period.

The provision expense attributable to the low volatile metallurgical coal segment was $38 million for the year ended December 31, 2011 compared to $27 million for the year ended December 31, 2010. The increased low volatile metallurgical coal provision expense per ton sold was attributable to the total Company's increased long-term liability expense discussed in the total Company results of operations section, offset, in part, by higher volumes of low volatile metallurgical coal sold. Low volatile metallurgical coal accretion expense related to mine closing and related liabilities decreased approximately $1 million in the period-to-period comparison as a result of the annual engineering surveys which contributed to lower average costs per ton sold.

Selling, administrative and other costs attributable to the low volatile metallurgical coal segment include selling, general and administrative expenses, direct administrative costs and water treatment expenses generated from the reverse osmosis plant. Selling, general and administrative costs, excluding commission expense and water treatment expense, are allocated to various segments on a combination of estimated time worked by various support groups and operating costs incurred at the mine. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct administrative costs are associated directly with the coal division of the business and are allocated to various mines based on a combination of estimated time worked and production. Selling, administrative and other costs related to the low volatile metallurgical coal segment were $28 million for the year ended December 31, 2011 compared to $18 million for the year ended December 31, 2010. The cost increase related to the low volatile metallurgical coal segment was attributable to higher selling, general and administrative expenses as discussed in the total Company results of operations section. Also, a reverse osmosis plant was completed and placed into service near the Buchanan Mine. Active mine water discharge is being treated by this facility and the costs of these services are charged to the mine based on gallons of water treated. Currently, the Buchanan Mine is the only facility using the plant. Construction of the plant was completed and the plant was placed into service in January 2011. These increases in expense were offset, in part, by higher volumes of low volatile metallurgical coal sold.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $37 million for the year ended December 31, 2011 compared to $21 million for the year ended December 31, 2010. The increase was primarily due to additional equipment, infrastructure and the reverse osmosis plant placed into service after the 2010 period that is depreciated on a straight-line basis. These increases in average costs per ton sold were offset, in part, by higher low volatile metallurgical tons sold which lowered the unit cost per ton impact.

OTHER COAL SEGMENT

The other coal segment had a loss before income tax of $339 million for the year ended December 31, 2011 compared to a loss before income tax of $394 million for the year ended December 31, 2010. The other coal segment includes purchased coal activities, idle mine activities, as well as various activities assigned to the coal segment but not allocated to each individual mine.

Other coal segment produced coal sales includes revenue from the sale of 0.4 million tons of coal which was recovered during the reclamation process at idled facilities for the year ended December 31, 2011 compared to 0.2 million tons for the year ended December 31, 2010. The primary focus of the activity at these locations is reclaiming disturbed land in accordance with the mining permit requirements after final mining has occurred. The tons sold are incidental to total Company production or sales.

Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes to meet customer coal specifications, coal purchased from third parties and sold directly to our customers and revenues from processing third-party coal in our preparation plants. The revenues were $42 million for the year ended December 31, 2011 compared to $34 million for the year ended December 31, 2010. The increase was primarily due to increased volumes sold partially offset by a decrease in the average sales price.

Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is almost completely offset in freight expense. Freight revenue was $232 million for the year ended December 31, 2011 compared to $126 million for the year ended December 31, 2010. The increase in freight revenue was primarily due to the 3.6 million ton increase in export tons in the period-to-period comparison.

Miscellaneous other income was $62 million for the year ended December 31, 2011 compared to $48 million for the year ended December 31, 2010. The increase of $14 million was primarily related to issuing pipeline right-of-ways to third parties which resulted in a gain of $12 million and various other transactions that occurred throughout both periods, none of which were individually material.

Other coal segment total costs were $702 million for the year ended December 31, 2011 compared to $614 million for the year ended December 31, 2010. The increase of $88 million was due to the following items:

	For the Years Ended December 31,		
	2011	2010	Variance
Abandonment of long-lived assets	$116	$—	$116
Freight expense	231	126	105
Purchased Coal	71	40	31
Coal contract buyout	5	—	5
Closed and idle mines	107	222	(115)
Litigation expense	8	55	(47)
Other	164	171	(7)
Total other coal segment costs	$702	$614	$88

- Abandonment of long-lived assets was $116 million for the year ended December 31, 2011 as a result of permanently idling Mine 84.
- Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight expense is almost completely offset in freight revenue. The increase was primarily due to the 3.6 million ton increase in export tons in the period-to-period comparison.
- Purchased coal costs increased approximately $31 million in the period-to-period comparison primarily due to differences in the quality of coal purchased, increases in the market price of coal purchased, and an increase in the volumes of coal purchased in the period-to-period comparison.
- Coal contract buyout costs increased $5 million as a result of a lower priced coal sales contract being bought out in order to sell the tons at a higher price in a future period.
- Closed and idle mine costs decreased approximately $115 million in the year ended December 31, 2011 compared to the year ended December 31, 2010. In the 2010 period, as a result of market conditions, permitting issues, new regulatory requirements and the resulting changes in mining plans, the reclamation liability associated with the Fola mining operations in West Virginia increased $82 million. Also in the 2010 period, closed and idle mine costs increased approximately $14 million as the result of the change in mine plan at Mine 84. As a result of the mine plan change, a portion of the previously developed area of the mine was abandoned. Closed and idle mine costs decreased $9 million as a result of the decision to permanently abandon Mine 84. Closed and idle mine costs for the 2010 period also included $6 million related to various asset abandonments that occurred, none of which were individually material. In addition, $9 million of reduced expenses were recognized in closed and idle mine costs for various changes in the operational status of other mines, between idled and operating, throughout both periods, none of which were individually material. Closed and idle mine costs increased $5 million in the 2011 period due to a charge for an additional liability due to Pennsylvania stream remediation.
- Litigation expense of $25 million was recognized in the year ended December 31, 2010 related to a legal settlement related to water discharge from our Buchanan Mine being stored in mine voids of adjacent properties which were leased by CONSOL Energy subsidiaries. Litigation expense was also recognized in the year ended December 31, 2010 related to a settlement that included the sale of Jones Fork which resulted in a loss of $10 million. Litigation expense related to various other potential legal settlements decreased $12 million in the period-to-period comparison. None of these items were individually material.
- Other costs related to the coal segment decreased $7 million due to various other transactions that occurred throughout both periods, none of which are individually material.

TOTAL GAS SEGMENT ANALYSIS for the year ended December 31, 2011 compared to the year ended December 31, 2010:
The gas segment contributed $130 million to earnings before income tax for the year ended December 31, 2011 compared to $180 million for the year ended December 31, 2010.

	For the Year Ended December 31, 2011					Difference to Year Ended December 31, 2010				
	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas	CBM	Shallow Oil and Gas	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$461	$155	$119	$12	$747	$(106)	$39	$70	$4	$7
Related Party	5	—	—	—	5	(1)	—	—	—	(1)
Total Outside Sales	466	155	119	12	752	(107)	39	70	4	6
Gas Royalty Interest	—	—	—	67	67	—	—	—	4	4
Purchased Gas	—	—	—	4	4	—	—	—	(7)	(7)
Other Income	—	—	—	59	59	—	—	—	54	54
Total Revenue and Other Income	466	155	119	142	882	(107)	39	70	55	57
Lifting	52	60	16	3	131	2	30	11	1	44
Gathering	98	27	15	2	142	1	9	5	(1)	14
General & Direct Administration	61	30	17	4	112	(4)	8	9	6	19
Depreciation, Depletion and Amortization	101	61	35	10	207	(12)	11	15	3	17
Gas Royalty Interest	—	—	—	59	59	—	—	—	5	5
Purchased Gas	—	—	—	4	4	—	—	—	(6)	(6)
Exploration and Other Costs	—	—	—	18	18	—	—	—	(7)	(7)
Other Corporate Expenses	—	—	—	65	65	—	—	—	9	9
Interest Expense	—	—	—	10	10	—	—	—	3	3
Total Cost	312	178	83	175	748	(13)	58	40	13	98
Earnings Before Noncontrolling Interest and Income Tax	154	(23)	36	(33)	134	(94)	(19)	30	42	(41)
Noncontrolling Interest	—	—	—	4	4	—	—	—	9	9
Earnings Before Income Tax	$154	$(23)	$36	$(37)	$130	$(94)	$(19)	$30	$33	$(50)

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $154 million to the total Company earnings before income tax for the year ended December 31, 2011 compared to $248 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Produced gas CBM sales volumes (in billion cubic feet)	92.4	91.4	1.0	1.1 %
Average CBM sales price per thousand cubic feet sold	$ 5.05	$ 6.27	$ (1.22)	(19.5)%
Average CBM lifting costs per thousand cubic feet sold	$ 0.56	$ 0.54	$ 0.02	3.7 %
Average CBM gathering costs per thousand cubic feet sold	$ 1.06	$ 1.06	$ —	— %
Average CBM general & direct administrative costs per thousand cubic feet sold	$ 0.66	$ 0.70	$ (0.04)	(5.7)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	$ 1.10	$ 1.25	$ (0.15)	(12.0)%
Total Average CBM costs per thousand cubic feet sold	$ 3.38	$ 3.55	$ (0.17)	(4.8)%
Average Margin for CBM	$ 1.67	$ 2.72	$ (1.05)	(38.6)%

CBM sales revenues were $466 million for the year ended December 31, 2011 compared to $573 million for the year ended December 31, 2010. The $107 million decrease was primarily due to a 19.5% decrease in average sales price per thousand cubic feet sold, offset, in part, by a 1.1% increase in average volumes sold. The decrease in CBM average sales price is the result of various gas swap transactions that matured in each period and lower average market prices. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 61.8 billion cubic feet of our produced CBM gas sales volumes for the year ended December 31, 2011 at an average price of $5.36 per thousand cubic feet. For the year ended December 31, 2010, these financial hedges represented 50.5 billion cubic feet at an average price of $7.73 per thousand cubic feet. CBM sales volumes increased 1.0 billion cubic feet primarily due to additional wells coming on-line from our on-going drilling program. At December 31, 2011 and 2010 there were 4,262 and 4,020 CBM wells in production, respectively.

Total costs for the CBM segment were $312 million for the year ended December 31, 2011 compared to $325 million for the year ended December 31, 2010. Lower costs in the period-to-period comparison are primarily related to lower unit costs.

CBM lifting costs were $52 million for the year ended December 31, 2011 compared to $50 million for the year ended December 31, 2010. Lifting costs increased primarily due to increased road maintenance, additional tank repairs, and additional maintenance on older wells.

CBM gathering costs were $98 million for the year ended December 31, 2011 compared to $97 million for the year ended December 31, 2010. CBM gathering unit costs remained consistent in the period-to-period comparison.

General and direct administrative costs attributable to the total gas division were $112 million for the year ended December 31, 2011 compared to $93 million for the year ended December 31, 2010. The $19 million increase was attributable to additional corporate service charges from CONSOL Energy and additional staffing. Corporate service charge allocations are primarily based on revenue and capital expenditure projections between coal and gas as a percent of total. The additional staffing is primarily due to the majority of the operational support staff being retained from the Dominion Acquisition which closed on April 30, 2010.

General and direct administrative costs for the CBM segment were $61 million for year ended December 31, 2011 compared to $65 million for the year ended December 31, 2010. General and direct administrative costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. Lower general and direct administrative costs attributable to the CBM segment was attributable to the increase in other gas segment volumes.

Depreciation, depletion and amortization attributable to the CBM segment was $101 million for the year ended December 31, 2011 compared to $113 million for the year ended December 31, 2010. There was approximately $72 million, or $0.78 per unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2011. The production portion of depreciation, depletion and amortization was $87 million, or $0.98 per unit-of-production in the year ended December 31, 2010. The CBM unit-of-production rate decreased due to revised rates which are generally calculated using the net book

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value of assets divided by either proved or proved developed reserve additions. There was approximately $29 million, or $0.32 average per unit cost of depreciation, depletion and amortization relating to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2011. The non-production related depreciation, depletion and amortization was $26 million, or $0.27 per thousand cubic feet for the year ended December 31, 2010. The increase was related to additional gathering assets placed in service after the 2010 period.

SHALLOW OIL AND GAS SEGMENT

The shallow oil and gas segment had a loss before income tax of $23 million for the year ended December 31, 2011 compared to a loss before income tax of $4 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Produced gas Shallow Oil and Gas sales volumes (in billion cubic feet)	32.2	24.7	7.5	30.4 %
Average Shallow Oil and Gas sales price per thousand cubic feet sold	$4.83	$4.73	$0.10	2.1 %
Average Shallow Oil and Gas lifting costs per thousand cubic feet sold	$1.86	$1.24	$0.62	50.0 %
Average Shallow Oil and Gas gathering costs per thousand cubic feet sold	$0.83	$0.75	$0.08	10.7 %
Average Shallow Oil and Gas general & direct administrative costs per thousand cubic feet sold	$0.94	$0.88	$0.06	6.8 %
Average Shallow Oil and Gas depreciation, depletion and amortization costs per thousand cubic feet sold	$1.92	$2.03	$(0.11)	(5.4)%
Total Average Shallow Oil and Gas costs per thousand cubic feet sold	$5.55	$4.90	$0.65	13.3 %
Average Margin for Shallow Oil and Gas	$(0.72)	$(0.17)	$(0.55)	323.5 %

Shallow Oil and Gas sales revenues were $155 million for the year ended December 31, 2011 compared to $116 million for the year ended December 31, 2010. The $39 million increase was primarily due to the 30.4% increase in volumes sold as well as the 2.1% increase in average sales price. Shallow Oil and Gas sales volumes increased 7.5 billion cubic feet in the year ended December 31, 2011 compared to the 2010 period primarily due to the Dominion Acquisition, which closed on April 30, 2010. Approximately 95% of the acquired producing wells were Shallow Oil and Gas type wells. Average sales price increased primarily as the result of various gas swap transactions that matured in the year ended December 31 2011, offset, in part by lower average market prices. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 11.5 billion cubic feet of our produced Shallow Oil and Gas gas sales volumes for the year ended December 31, 2011 at an average price of $4.97 per thousand cubic feet. There were no Shallow Oil and Gas gas swap transactions that occurred in the year ended December 31, 2010. There were 8,041 and 8,016 shallow oil and gas wells in production at December 31, 2011 and 2010, respectively.

Shallow Oil and Gas lifting costs were $60 million for the year ended December 31, 2011 compared to $30 million for the year ended December 31, 2010. Lifting costs per unit increased $0.62 per thousand cubic feet sold primarily due to increased road maintenance, increased well site maintenance, increased salt water disposal and additional well services performed to maintain production levels.

Shallow Oil and Gas gathering costs were $27 million for the year ended December 31, 2011 compared to $18 million for the year ended December 31, 2010. Average gathering costs increased $0.08 per unit primarily due to additional compressor maintenance.

General and direct administrative costs for the Shallow Oil and Gas gas segment were $30 million for the year ended December 31, 2011 compared to $22 million for the year ended December 31, 2010. General and direct administrative costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The total general and direct administrative costs increases which were discussed in the CBM segment and higher volumes of Shallow Oil and Gas gas sold contributed to the increase in the Shallow Oil and Gas gas segment. General and direct administrative costs were $0.94 per thousand cubic feet sold for the year ended December 31, 2011 compared to $0.88 per thousand cubic feet sold for the year ended December 31, 2010.

Depreciation, depletion and amortization costs were $61 million for the year ended December 31, 2011 compared to $50 million for the year ended December 31, 2010. There was approximately $54 million, or $1.69 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2011. There was approximately $45 million, or

$1.84 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the year ended December 31, 2010. The rate was calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $7 million, or $0.23 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis for the year ended December 31, 2011. There was $5 million, or $0.19 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2010. The increase was related to additional infrastructure and equipment placed in service after the 2010 period.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $36 million to the total Company earnings before income tax for the year ended December 31, 2011 compared to $6 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Produced gas Marcellus sales volumes (in billion cubic feet)	26.9	10.4	16.5	158.7 %
Average Marcellus sales price per thousand cubic feet sold	$4.43	$4.69	$(0.26)	(5.5)%
Average Marcellus lifting costs per thousand cubic feet sold	$0.60	$0.50	$0.10	20.0 %
Average Marcellus gathering costs per thousand cubic feet sold	$0.54	$0.99	$(0.45)	(45.5)%
Average Marcellus general & direct administrative costs per thousand cubic feet sold	$0.64	$0.73	$(0.09)	(12.3)%
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	$1.32	$1.90	$(0.58)	(30.5)%
Total Average Marcellus costs per thousand cubic feet sold	$3.10	$4.12	$(1.02)	(24.8)%
Average Margin for Marcellus	$1.33	$0.57	$0.76	133.3 %

The Marcellus segment sales revenues were $119 million for the year ended December 31, 2011 compared to $49 million for the year ended December 31, 2010. The $70 million increase was primarily due to a 158.7% increase in average volumes sold, offset, in part, by a 5.5% decrease in average sales price per thousand cubic feet sold. The increase in sales volumes is primarily due to additional wells coming on-line from our on-going drilling program, partially offset by 6.6 billion cubic feet related to the Noble joint venture and 1.0 billion cubic feet related to the Antero sale. The decrease in Marcellus average sales price was the result of the decline in general market prices. These decreases were offset, in part, by various gas swap transactions that matured in the year ended December 31, 2011. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These hedges represented approximately 10.6 billion cubic feet of our produced Marcellus gas sales volumes for the year ended December 31, 2011 at an average price of $4.64 per thousand cubic feet. For the year ended December 31, 2010, these financial hedges represented 1.6 billion cubic feet at an average price of $5.05 per thousand cubic feet. At December 31, 2011 and 2010, there were 110 and 52 gross Marcellus Shale wells in production, respectively.

Marcellus lifting costs were $16 million for the year ended December 31, 2011 compared to $5 million for the year ended December 31, 2010. Lifting costs per unit increased $0.10 per thousand cubic feet sold primarily due to increased expenses for well clean out and tubing replacement services performed to improve production.

Marcellus gathering costs were $15 million for the year ended December 31, 2011 compared to $10 million for the year ended December 31, 2010. Average gathering costs decreased $0.45 per unit primarily due to the 16.5 billion cubic feet of additional volumes sold.

General and direct administrative costs for the Marcellus gas segment were $17 million for the year ended December 31, 2011 compared to $8 million for the year ended December 31, 2010. General and direct administrative costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The total general and direct administrative costs increases which were discussed in the CBM segment and higher volumes of Marcellus gas sold contributed to the increase in the Marcellus gas segment. General and direct administrative costs were $0.64 per thousand cubic feet sold for the year ended December 31, 2011 compared to $0.73 per thousand cubic feet sold for the year ended December 31, 2010.

Depreciation, depletion and amortization costs were $35 million for the year ended December 31, 2011 compared to $20 million for the year ended December 31, 2010. There was approximately $27 million, or $1.04 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2011. There was approximately $18 million, or $1.72 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the year ended December 31, 2010. The rate was calculated by taking the net book value of the related assets divided by either proved or proved developed reserves, generally at the previous year end. There was approximately $8 million, or $0.28 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis for the year ended December 31, 2011. There was $2 million, or $0.18 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2010. The increase was related to additional infrastructure and equipment placed in service after the 2010 period.

OTHER GAS SEGMENT

The other gas segment includes activity not assigned to the CBM, conventional or Marcellus gas segments. This segment includes purchased gas activity, gas royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific gas segment.

Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee. Revenue from this operation was approximately $12 million for the year ended December 31, 2011 and $8 million for the year ended December 31, 2010. Total costs related to these other sales were $19 million for the 2011 period and were $10 million for the 2010 period. The increase in costs in the period-to-period comparison were primarily attributable to increased general and direct administrative costs allocated to the other gas segment and increased depreciation, depletion and amortization. Higher general and direct administrative costs were attributable to the total gas increase as discussed in the CBM segment coupled with increased sales volumes. Higher depreciation, depletion and amortization was due to higher volumes produced and higher unit of production rates. A per unit analysis of the other operating costs in the Chattanooga shale is not meaningful due to the low volumes produced in the period-to-period analysis.

Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas division. Royalty interest gas sales revenue was $67 million for the year ended December 31, 2011 compared to $63 million for the year ended December 31, 2010. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	16.4	14.2	2.2	15.5 %
Average Sales Price Per thousand cubic feet	$4.07	$4.41	$(0.34)	(7.7)%

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $4 million for the year ended December 31, 2011 compared to $11 million for the year ended December 31, 2010.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	1.0	2.0	(1.0)	(50.0)%
Average Sales Price Per thousand cubic feet	$4.28	$5.48	$(1.20)	(21.9)%

Other income was $59 million for the year ended December 31, 2011 compared to $5 million for the year ended December 31, 2010. The $54 million increase was primarily due to a gain on the Hess transaction of $53 million, a gain on the sale of the Antero overriding royalty interest of $41 million, $8 million of additional interest income related to the notes receivable related to the Noble joint venture transaction, $5 million due to various transactions that occurred throughout both periods, none of which were individually material and $4 million due to increased earnings from equity affiliates. These improvements were partially offset by a loss on the Noble transaction of $57 million.

Royalty interest gas costs represent the costs related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas costs were $59 million for the year ended December 31, 2011 compared to $54 million for the year ended December 31, 2010. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Years Ended December 31,			
	2011	2010	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	16.4	14.2	2.2	15.5 %
Average Cost Per thousand cubic feet sold	$ 3.61	$ 3.78	$ (0.17)	(4.5)%

Purchased gas volumes represent volumes of gas purchased from third-party producers that we sell. Purchased gas volumes also reflect the impact of pipeline imbalances. The lower average cost per thousand cubic feet is due to overall price changes and contractual differences among customers in the period-to-period comparison. Purchased gas costs were $4 million for the year ended December 31, 2011 compared to $10 million for the year ended December 31, 2010.