CONSOL Energy Inc
Form 10-Q
October 31, 2011

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

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.

For the quarterly period ended September 30, 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)

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 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

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Shares outstanding as of October 19, 2011

Common stock, $0.01 par value	226,821,506

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PART I
FINANCIAL INFORMATION

ITEM 1. CONDENSED FINANCIAL STATEMENTS

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)
(Dollars in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Sales—Outside	$1,421,689	$1,260,499	$4,293,167	$3,650,129
Sales—Gas Royalty Interests	17,083	18,131	52,191	46,621
Sales—Purchased Gas	1,155	3,524	3,297	8,280
Freight—Outside	59,871	37,269	156,311	96,544
Other Income	21,931	29,870	70,068	77,126
Total Revenue and Other Income	1,521,729	1,349,293	4,575,034	3,878,700
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	879,268	850,819	2,620,376	2,436,452
Transaction and Financing Fees	14,907	337	14,907	64,415
Loss on Debt Extinguishment	—	—	16,090	—
Gas Royalty Interests Costs	15,409	16,408	46,582	40,133
Purchased Gas Costs	398	3,333	2,850	6,980
Freight Expense	59,871	37,269	156,122	96,544
Selling, General and Administrative Expenses	46,692	38,722	130,311	107,897
Depreciation, Depletion and Amortization	159,750	161,429	466,612	413,379
Abandonment of Long-Lived Assets	338	—	115,817	—
Interest Expense	58,884	66,430	189,963	139,613
Taxes Other Than Income	85,790	83,406	265,121	243,831
Total Costs	1,321,307	1,258,153	4,024,751	3,549,244
Earnings Before Income Taxes	200,422	91,140	550,283	329,456
Income Taxes	33,093	15,757	113,421	75,291
Net Income	167,329	75,383	436,862	254,165
Less: Net Income Attributable to Noncontrolling Interest	—	—	—	(11,845)
Net Income Attributable to CONSOL Energy Inc. Shareholders	$167,329	$75,383	$436,862	$242,320
Earnings Per Share:				
Basic	$0.74	$0.33	$1.93	$1.15
Dilutive	$0.73	$0.33	$1.91	$1.13
Weighted Average Number of Common Shares Outstanding:				
Basic	226,744,011	225,781,539	226,582,226	211,235,893
Dilutive	229,163,537	228,092,299	229,002,863	213,638,176
Dividends Paid Per Share	$0.10	$0.10	$0.30	$0.30

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

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CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	(Unaudited) September 30, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$472,523	$32,794
Accounts and Notes Receivable:		
Trade	503,076	252,530
Other Receivables	331,614	21,589
Accounts Receivable—Securitized	—	200,000
Inventories	241,691	258,538
Deferred Income Taxes	157,247	174,171
Recoverable Income Taxes	11,504	32,528
Prepaid Expenses	184,263	142,856
Total Current Assets	1,901,918	1,115,006
Property, Plant and Equipment:		
Property, Plant and Equipment	13,837,263	14,951,358
Less—Accumulated Depreciation, Depletion and Amortization	4,766,163	4,822,107
Total Property, Plant and Equipment—Net	9,071,100	10,129,251
Other Assets:		
Deferred Income Taxes	458,858	484,846
Restricted Cash	20,291	20,291
Investment in Affiliates	175,818	93,509
Other	535,063	227,707
Total Other Assets	1,190,030	826,353
TOTAL ASSETS	$12,163,048	$12,070,610

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

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands, except per share data)

	(Unaudited) September 30, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts Payable	$448,667	$354,011
Short-Term Notes Payable	—	284,000
Current Portion of Long-Term Debt	20,306	24,783
Borrowings Under Securitization Facility	—	200,000
Other Accrued Liabilities	833,939	801,991
Total Current Liabilities	1,302,912	1,664,785
Long-Term Debt:		
Long-Term Debt	3,123,434	3,128,736
Capital Lease Obligations	55,298	57,402
Total Long-Term Debt	3,178,732	3,186,138
Deferred Credits and Other Liabilities:		
Postretirement Benefits Other Than Pensions	3,094,164	3,077,390
Pneumoconiosis Benefits	177,162	173,616
Mine Closing	401,049	393,754
Gas Well Closing	118,525	130,978
Workers' Compensation	149,827	148,314
Salary Retirement	114,543	161,173
Reclamation	39,513	53,839
Other	159,878	144,610
Total Deferred Credits and Other Liabilities	4,254,661	4,283,674
TOTAL LIABILITIES	8,736,305	9,134,597
Stockholders' Equity:		
Common Stock, $.01 Par Value; 500,000,000 Shares Authorized, 227,289,426 Issued and 226,781,351 Outstanding at September 30, 2011; 227,289,426 Issued and 226,162,133 Outstanding at December 31, 2010	2,273	2,273
Capital in Excess of Par Value	2,219,783	2,178,604
Preferred Stock, 15,000,000 shares authorized, None issued and outstanding	—	—
Retained Earnings	2,025,794	1,680,597
Accumulated Other Comprehensive Loss	(800,896)	(874,338)
Common Stock in Treasury, at Cost—508,075 Shares at September 30, 2011 and 1,127,293 Shares at December 31, 2010	(20,211)	(42,659)
Total CONSOL Energy Inc. Stockholders' Equity	3,426,743	2,944,477
Noncontrolling Interest	—	(8,464)
TOTAL EQUITY	3,426,743	2,936,013
TOTAL LIABILITIES AND EQUITY	$12,163,048	$12,070,610

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

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Dollars in thousands, except per share data)

	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total CONSOL Energy Inc. Stockholders' Equity	Non-Controlling Interest	Total Equity
Balance at December 31, 2010	$2,273	$2,178,604	$1,680,597	$(874,338)	$(42,659)	$2,944,477	$(8,464)	$2,936,013
(Unaudited)								
Net Income	—	—	436,862	—	—	436,862	—	436,862
Treasury Rate Lock (Net of $59 Tax)	—	—	—	(96)	—	(96)	—	(96)
Gas Cash Flow Hedge (Net of $22,767 Tax)	—	—	—	35,702	—	35,702	—	35,702
Actuarially Determined Long-Term Liability Adjustments (Net of $23,547 Tax)	—	—	—	37,836	—	37,836	—	37,836
Comprehensive Income (Loss)	—	—	436,862	73,442	—	510,304	—	510,304
Issuance of Treasury Stock	—	—	(23,693)	—	22,448	(1,245)	—	(1,245)
Tax Benefit From Stock-Based Compensation	—	4,096	—	—	—	4,096	—	4,096
Amortization of Stock-Based Compensation Awards	—	37,083	—	—	—	37,083	—	37,083
Net Change in Noncontrolling Interest	—	—	—	—	—	—	8,464	8,464
Dividends ($0.30 per share)	—	—	(67,972)	—	—	(67,972)	—	(67,972)
Balance at September 30, 2011	$2,273	$2,219,783	$2,025,794	$(800,896)	$(20,211)	$3,426,743	$—	$3,426,743

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

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(Dollars in thousands)

	Nine Months Ended September 30, 2011	2010
Operating Activities:		
Net Income	$436,862	$254,165
Adjustments to Reconcile Net Income to Net Cash Provided By Operating Activities:		
Depreciation, Depletion and Amortization	466,612	413,379
Abandonment of Long-Lived Assets	115,817	—
Stock-Based Compensation	37,083	33,580
Loss (Gain) on Sale of Assets	9,993	(8,475)
Loss on Debt Extinguishment	16,090	—
Amortization of Mineral Leases	4,149	3,890
Deferred Income Taxes	120	3,372
Equity in Earnings of Affiliates	(19,989)	(15,595)
Changes in Operating Assets:		
Accounts and Notes Receivable	(50,212)	(66,840)
Inventories	16,264	45,126
Prepaid Expenses	(611)	(26,216)
Changes in Other Assets	16,446	23,764
Changes in Operating Liabilities:		
Accounts Payable	98,320	63,168
Other Operating Liabilities	66,589	109,371
Changes in Other Liabilities	29,432	14,051
Other	9,439	32,190
Net Cash Provided by Operating Activities	1,252,404	878,930
Investing Activities:		
Capital Expenditures	(997,463)	(821,908)
Acquisition of Dominion Exploration and Production Business	—	(3,474,199)
Purchase of CNX Gas Noncontrolling Interest	—	(991,034)
Proceeds from Sales of Assets	695,291	24,944
Distributions from Equity Affiliates	70,860	6,867
Net Cash Used in Investing Activities	(231,312)	(5,255,330)
Financing Activities:		
Payments on Short-Term Borrowings	(284,000)	(258,950)
Payments on Miscellaneous Borrowings	(9,320)	(8,564)
(Payments on) Proceeds from Securitization Facility	(200,000)	150,000
Payments on Long-Term Notes, Including Redemption Premium	(265,785)	—
Proceeds from Issuance of Long-Term Notes	250,000	2,750,000
Tax Benefit from Stock-Based Compensation	5,034	9,926
Dividends Paid	(67,972)	(63,276)
Proceeds from Issuance of Common Stock	—	1,828,862
Issuance of Treasury Stock	6,219	2,601
Debt Issuance and Financing Fees	(15,539)	(84,224)
Net Cash (Used In) Provided By Financing Activities	(581,363)	4,326,375
Net Increase (Decrease) in Cash and Cash Equivalents	439,729	(50,025)

Cash and Cash Equivalents at Beginning of Period	32,794	65,607
Cash and Cash Equivalents at End of Period	$472,523	$15,582

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

CONSOL ENERGY INC. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except per share data)

NOTE 1—BASIS OF PRESENTATION:

The accompanying Unaudited Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the three and nine months ended September 30, 2011 are not necessarily indicative of the results that may be expected for future periods.

The balance sheet at December 31, 2010 has been derived from the Audited Consolidated Financial Statements at that date but does not include all the notes required by generally accepted accounting principles for complete financial statements. For further information, refer to the Consolidated Financial Statements and related notes for the year ended December 31, 2010 included in CONSOL Energy Inc.'s Form 10-K.

Basic earnings per share are computed by dividing net income by the weighted average shares outstanding during the reporting period. Dilutive earnings per share are computed similarly to basic earnings per share except that the weighted average shares outstanding are increased to include additional shares from the assumed exercise of stock options and performance stock options and the assumed vesting of restricted and performance stock units, if dilutive. The number of additional shares is calculated by assuming that outstanding stock options and performance share options were exercised, that outstanding restricted and performance share units were released, and that the proceeds from such activities were used to acquire shares of common stock at the average market price during the reporting period. CONSOL Energy Inc. (CONSOL Energy or Company) includes the impact of pro forma deferred tax assets in determining potential windfalls and shortfalls for purposes of calculating assumed proceeds under the treasury stock method. The table below sets forth the share-based awards that have been excluded from the computation of the diluted earnings per share because their effect would be anti-dilutive:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Anti-Dilutive Options	1,154,051	819,189	1,154,051	819,189
Anti-Dilutive Restricted Stock Units	—	—	—	1,960
Anti-Dilutive Performance Share Units	21,675	—	—	—
	1,175,726	819,189	1,154,051	821,149

The table below sets forth the share-based awards that have been exercised or released:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Options	72,254	23,562	311,003	146,555
Restricted Stock Units	20,589	35,355	424,958	340,699
Performance Share Units	—	—	40,752	109,955
	92,843	58,917	776,713	597,209

The weighted average exercise price per share of the options exercised during the three months ended September 30, 2011 and 2010 was $16.69 and $16.01, respectively. The weighted average exercise price per share of the options exercised during the nine months ended September 30, 2011 and 2010 was $20.00 and $17.69, respectively.

The computations for basic and dilutive earnings per share are as follows:

	Three Month Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income attributable to CONSOL Energy Inc. shareholders	$167,329	$75,383	$436,862	$242,320
Weighted average shares of common stock outstanding:				
Basic	226,744,011	225,781,539	226,582,226	211,235,893
Effect of stock-based compensation awards	2,419,526	2,310,760	2,420,637	2,402,283
Dilutive	229,163,537	228,092,299	229,002,863	213,638,176
Earnings per share:				
Basic	$0.74	$0.33	$1.93	$1.15
Dilutive	$0.73	$0.33	$1.91	$1.13

NOTE 2—ACQUISITIONS AND DISPOSITIONS:

On September 30, 2011, CNX Gas Company (CNX Gas) 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 acres and 50% of the Company's undivided interest in certain of its existing Marcellus Shale wells and related leases. On September 30, 2011, cash proceeds of $519,188 were received from Noble. In addition to the cash proceeds, a one year note receivable due on September 30, 2012 in the amount of $311,754 and a two year note receivable due on September 30, 2013 in the amount of $296,343 have been recorded. These short and long-term notes receivable are included in the Consolidated Balance Sheets as Accounts and Notes Receivables—Other Receivables and Other Assets—Other, respectively. A loss of $64,429 on the transaction was recorded and is included in Other Income on the Consolidated Statements of Income. As part of the transaction, CONSOL Energy also received a commitment from Noble Energy to pay one-third of the Company's working interest share of certain drilling and completion costs, up to approximately $2,100,000 with certain restrictions.

The following unaudited pro forma combined financial statements are based on CONSOL Energy's historical consolidated financial statements and adjusted to give effect to the September 30, 2011 sale of a 50% interest in certain Marcellus Shale assets. The unaudited pro forma results for the periods presented below are prepared as if the transaction occurred as of January 1, 2010.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Total Revenue and Other Income	$1,502,660	$1,341,784	$4,531,696	$3,862,000
Earnings Before Income Taxes	$195,882	$89,936	$538,152	$327,324
Net Income Attributable to CONSOL Energy Inc. Shareholders	$163,822	$74,458	$427,491	$240,683
Basic Earnings Per Share	$0.72	$0.33	$1.89	$1.14
Dilutive Earnings Per Share	$0.71	$0.33	$1.87	$1.12

The pro forma results are not necessarily indicative of what actually would have occurred if the transaction had been completed as of January 1, 2010, nor are they necessarily indicative of future consolidated results.

On September 30 2011, CNX Gas 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' 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 $133,181 and Noble contributed cash of approximately $73,492. On September 30, 2011, CONE made a cash distribution to CNX Gas in the amount of

$73,492. The cash proceeds have been recorded as cash inflows of $66,590 and $6,902 in Distributions from Equity Affiliates and Proceeds from the Sale of Assets, respectively, on the Consolidated Statement of Cash Flows. Additionally, a gain of $6,388 has been included in Other Income in the Consolidated Statements of 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 115,647 net acres of Marcellus Shale located in nine counties in southwestern Pennsylvania and north central West Virginia, in exchange for $193,000. The net gain of $41,208 is included in Other Income in the Consolidated Statements of Income.

In September 2010, CONSOL Energy completed a sale-leaseback of longwall shields for Enlow Fork. Cash proceeds from the sale were $14,551, which was the same as our basis in the equipment. Accordingly, no gain or loss was recognized on the transaction. The lease has been accounted for as an operating lease. The lease term is five years.

In June 2010, CONSOL Energy paid Yukon Pocahontas Coal Company $30,000 cash to acquire certain coal reserves and $20,000 cash in advanced royalty payments recoupable against future production. Both payments were made per a settlement agreement in regards to the depositing of untreated water from the Buchanan Mine, a mine operated by one of our subsidiaries, into the void spaces of the nearby mines of one of our other subsidiaries, Island Creek Coal Company.

On June 1, 2010, CONSOL Energy completed the acquisition of CNX Gas Corporation (CNX Gas) outstanding common stock for a cash payment of $966,811 pursuant to a tender offer followed by a short-form merger in which CNX Gas became a wholly owned subsidiary of CONSOL Energy (CNX Gas Acquisition). All of the shares of CNX Gas that were not already owned by CONSOL Energy were acquired at a price of $38.25 per share. CONSOL Energy previously owned approximately 83.3% of the approximately 151 million shares of CNX Gas common stock outstanding. An additional $24,223 cash payment was made to cancel previously vested but unexercised CNX Gas stock options. CONSOL Energy financed the acquisition of CNX Gas shares by means of internally generated funds, borrowings under its credit facilities and proceeds from its offering of common stock.

On April 30, 2010, CONSOL Energy completed the acquisition of the Appalachian oil and gas exploration and production business of Dominion Resources, Inc. (Dominion Acquisition) for a cash payment as of September 30, 2010 of $3,474,199 which was principally allocated to oil & gas properties, wells and well-related equipment. The acquisition, which was accounted for under the acquisition method of accounting, includes approximately 1 trillion cubic feet equivalents (Tcfe) of net proved reserves and 1.46 million net acres of oil and gas rights within the Appalachian Basin. Included in the acreage holdings are approximately 500 thousand prospective net Marcellus Shale acres located predominantly in southwestern Pennsylvania and northern West Virginia. Dominion is a producer and transporter of natural gas as well as a provider of electricity and related services. The acquisition enhanced CONSOL Energy's position in the strategic Marcellus Shale fairway by increasing its development assets.

The unaudited pro forma results for the three and nine months ended September 30, 2010, assuming the acquisition had occurred at January 1, 2010, are presented below. Pro forma adjustments include estimated operating results, transaction and financing fees incurred, additional interest related to the $2.75 billion of senior unsecured notes and 44,275,000 shares of common stock issued in connection with the transaction.

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Total Revenue and Other Income	$1,349,293	$3,945,687
Earnings Before Income Taxes	$91,140	$275,748
Net Income Attributable to CONSOL Energy Inc. Shareholders	$75,383	$210,299
Basic Earnings Per Share	$0.33	$0.93
Dilutive Earnings Per Share	$0.33	$0.92

The pro forma results are not necessarily indicative of what actually would have occurred if the Dominion Acquisition had been completed as of January 1, 2010, nor are they necessarily indicative of future consolidated results.

CONSOL Energy incurred $337 and $64,415 of acquisition-related costs as a direct result of the Dominion Acquisition and CNX Gas Acquisition for the three and nine months ended September 30, 2010, respectively. These expenses have been included within Transaction and Financing Fees on the Consolidated Statements of Income for the period ended September 30, 2010.

In March 2010, CONSOL Energy completed the sale of the Jones Fork Mining Complex as part of a litigation settlement with Kentucky Fuel Corporation. No cash proceeds were received and $10,482 of litigation settlement expense was recorded in Cost of Goods Sold and Other Operating Charges. The loss recorded was net of $8,700 related to the fair value of estimated amounts to be collected related to an overriding royalty on future mineable and merchantable coal extracted and sold from the property.

NOTE 3—COMPONENTS OF PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS NET PERIODIC BENEFIT COSTS:

Components of net periodic costs for the three and nine months ended September 30 are as follows:

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended		Nine Months Ended		Three Months Ended		Nine Months Ended	
	September 30,		September 30,		September 30,		September 30,	
	2011	2010	2011	2010	2011	2010	2011	2010
Service cost	$4,364	$3,644	$13,093	$10,857	$3,419	$3,303	$10,258	$9,843
Interest cost	9,436	9,311	28,308	27,908	44,935	40,725	134,804	122,091
Expected return on plan assets	(9,631)	(9,262)	(28,892)	(27,786)	—	—	—	—
Amortization of prior service cost (credits)	(167)	(184)	(500)	(551)	(11,599)	(11,604)	(34,798)	(34,811)
Recognized net actuarial loss	9,526	7,968	28,577	23,903	26,341	17,537	79,023	52,609
Net periodic benefit cost	$13,528	$11,477	$40,586	$34,331	$63,096	$49,961	$189,287	$149,732

For the nine months ended September 30, 2011, $57,713 in contributions were paid to the pension trust for pension benefits from operating cash flows. CONSOL Energy expects to contribute to the pension trust using prudent funding methods. Currently, depending on asset values and asset returns held in the trust, we expect to contribute $71,700 to the pension trust in 2011.

CONSOL Energy does not expect to contribute to the other postemployment benefit plan in 2011. We intend to pay benefit claims as they become due. For the nine months ended September 30, 2011, $123,185 of other postemployment benefits have been paid.

For the nine months ended September 30, 2011, $7,781 of proceeds were received under the Patient Protection and Affordable Care Act related to reimbursements from the Federal government for retiree health spending. The proceeds were recorded in Accumulated Other Comprehensive Income in the Consolidated Balance Sheets. There is no guarantee that additional proceeds will be received under this program.

NOTE 4—COMPONENTS OF COAL WORKERS' PNEUMOCONIOSIS (CWP) AND WORKERS' COMPENSATION NET PERIODIC BENEFIT COSTS:

Components of net periodic costs (benefits) for the three and nine months ended September 30 are as follows:

	CWP				Workers' Compensation			
	Three Months Ended		Nine Months Ended		Three Months Ended		Nine Months Ended	
	September 30,		September 30,		September 30,		September 30,	
	2011	2010	2011	2010	2011	2010	2011	2010
Service cost	$1,155	$1,040	$3,465	$4,027	$4,468	$6,754	$13,404	$20,262
Interest cost	2,332	2,681	6,997	8,108	2,059	2,289	6,178	6,867
Amortization of actuarial gain	(5,477)	(5,777)	(16,432)	(16,536)	(977)	(768)	(2,930)	(2,304)
State administrative fees and insurance bond premiums	—	—	—	—	1,459	2,020	4,667	6,238
Legal and administrative costs	750	750	2,250	2,250	719	785	2,156	2,354
Net periodic (benefit) cost	$(1,240)	$(1,306)	$(3,720)	$(2,151)	$7,728	$11,080	$23,475	$33,417

CONSOL Energy does not expect to contribute to the CWP plan in 2011. We intend to pay benefit claims as they become due. For the nine months ended September 30, 2011, $8,833 of CWP benefit claims have been paid.

CONSOL Energy does not expect to contribute to the workers' compensation plan in 2011. We intend to pay benefit claims as they become due. For the nine months ended September 30, 2011, $23,314 of workers' compensation benefits, state administrative fees and surety bond premiums have been paid.

NOTE 5—INCOME TAXES:

The following is a reconciliation, stated in dollars and as a percentage of pretax income, of the U.S. statutory federal income tax rate to CONSOL Energy's effective tax rate:

	For the Nine Months Ended September 30,			
	2011		2010	
	Amount	Percent	Amount	Percent
Statutory U.S. federal income tax rate	$192,599	35.0 %	$115,310	35.0 %
Excess tax depletion	(76,561)	(13.9)	(49,852)	(15.1)
Effect of domestic production activities	(10,038)	(1.8)	(4,916)	(1.5)
Effect of federal tax accrual to tax return	(10,249)	(1.9)	3,163	1.0
IRS and state tax examination settlements	(5,187)	(0.9)	—	—
Net effect of state income taxes	16,088	2.9	9,220	2.8
Other	6,769	1.2	2,366	0.7
Income Tax Expense / Effective Rate	$113,421	20.6 %	$75,291	22.9 %

The effective rates for the nine months ended September 30, 2011 and 2010 were calculated using the annual effective rate projection on recurring earnings and include tax liabilities related to certain discrete transactions which are described below.

CONSOL Energy and its subsidiaries file income tax returns in the U.S. federal, various state and Canadian tax jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2008. The Internal Revenue Service has issued its audit report relating to the examination of CONSOL Energy's 2006 and 2007 U.S. income tax returns during the three months ended September 30, 2011. As a result of these findings, CONSOL Energy paid federal and state income tax deficiencies of $10,765 and $1,523, respectively. The federal and state income tax deficiencies paid were related of the IRS' examination of the Company's 2006 and 2007 tax returns and were the result of changes in the timing of certain tax deductions. The change in timing of certain tax deductions increased the tax benefit of percentage depletion by $2,594 and $908 in tax years 2006 and 2007, respectively. The

Company also realized a tax benefit of $981 on state income taxes related to the the federal percentage depletion increases.

For the nine months ended September 30, 2011, CONSOL Energy recognized certain tax benefits as a result of changes in estimates related to a prior-year tax provision. Due to the results of the IRS' audit of tax years 2006 and 2007 resulted in a tax position that increased the deduction for percentage depletion on the 2010 tax return compared to the 2010 tax accrual. The result of these changes was a tax reduction of $7,310. Additionally, the Company concluded, based on subsequent-year developments, that claiming a Foreign Tax Credit was more tax efficient than deducting foreign income taxes paid. This change resulted in a $3,331 reduction in tax expense. The actualization of various other estimates resulted in a tax increase of $392.

CONSOL Energy was advised by the Canadian Revenue Agency and various provinces that its appeal of tax deficiencies paid as a result of the Agency's audit of the Canadian tax returns filed for years 1997 through 2003 had been successfully resolved. As a result of the audit settlement, the Company reflected $3,424 as a discrete reduction to foreign income tax expense in the nine months ended September 30, 2010. As a result of the foreign income tax reduction, the Company reflected an additional $1,445 as discrete federal income tax expense. This discrete transaction was reflected in the Other line of the rate reconciliation in 2010.

As a result of the Dominion Acquisition, CONSOL Energy recognized a discrete state income tax expense of $1,782 due to the impact of the acquisition on existing deferred tax assets and liabilities in the nine months ended September 30, 2010. Accordingly, a discrete reduction to federal income tax expense of $624 was also recognized related to this transaction. This discrete transaction was reflected in the Net effect of state income taxes line of the rate reconciliation in 2010.

CONSOL Energy was notified by the state of Ohio that the state had completed its audit of the Company's net operating loss (NOL) carryovers. In 2010, Ohio completed a transition from an income and franchise tax to a Commercial Activities Tax (CAT). The state's audit concluded that CONSOL Energy is entitled to a credit for unused NOLs against future CAT liabilities. These NOLs were previously fully reserved. In the nine months ended September 30, 2010, CONSOL Energy recognized a discrete reduction to state income tax expense of $2,068 related to the reversal of the previously recognized NOL allowance based on the audit settlement. This discrete transaction was reflected in the Net effect of state income taxes line of the rate reconciliation in 2010.

The total amounts of uncertain tax positions at September 30, 2011 and 2010 were $42,932 and $56,916, respectively. If these uncertain tax positions were recognized, approximately $16,802 and $15,502, respectively, would affect CONSOL Energy’s effective tax rate. There were no additions to the liability for unrecognized tax benefits during the nine months ended September 30, 2011 and 2010. The reduction in unrecognized tax benefits in the nine months ended September 30, 2011, is a result of the completion of the Internal Revenue Service audit of the tax years 2006 and 2007 discussed above.

CONSOL Energy recognizes interest accrued related to uncertain tax positions in its interest expense. As of September 30, 2011 and 2010, the Company reported an accrued interest liability relating to uncertain tax positions of $7,309 and $10,578, respectively. The accrued interest liability includes $1,160 of interest income and $2,240 of interest expense that is reflected in the Company’s Consolidated Statements of Income for the nine months ended September 30, 2011 and 2010, respectively. The reduction in accrued interest related to unrecognized tax benefits in the nine months ended September 30, 2011, was the result of the completion of the Internal Revenue Service audit. During the nine months ended September 30, 2011, CONSOL Energy paid interest of $2,305 on federal income tax deficiencies previously recognized in interest accrued related to unrecognized tax benefits.

CONSOL Energy recognizes penalties accrued related to uncertain tax positions in its income tax expense. As of September 30, 2011 and 2010, CONSOL Energy had no accrued liability for tax penalties.

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NOTE 6—INVENTORIES:
Inventory components consist of the following:

	September 30, 2011	December 31, 2010
Coal	$90,914	$108,694
Merchandise for resale	42,140	50,120
Supplies	108,637	99,724
Total Inventories	$241,691	$258,538

Merchandise for resale is valued using the last-in, first-out (LIFO) cost method. The excess of replacement cost of merchandise for resale inventories over carrying LIFO value was $24,094 and $19,624 at September 30, 2011 and December 31, 2010, respectively.

NOTE 7—ACCOUNTS RECEIVABLE SECURITIZATION:
CONSOL Energy and certain of our U.S. subsidiaries are party to a trade accounts receivable facility with financial institutions for the sale on a continuous basis of eligible trade accounts receivable. The facility allows CONSOL Energy to receive on a revolving basis up to $200,000. The facility also allows for the issuance of letters of credit against the $200,000 capacity. At September 30, 2011, there were no letters of credit outstanding against the facility. CNX Funding Corporation, a wholly owned, special purpose, bankruptcy-remote subsidiary, buys and sells eligible trade receivables generated by certain subsidiaries of CONSOL Energy. Under the receivables facility, CONSOL Energy and certain subsidiaries, irrevocably and without recourse, sell all of their eligible trade accounts receivable to CNX Funding Corporation, who in turn sells these receivables to financial institutions and their affiliates, while maintaining a subordinated interest in a portion of the pool of trade receivables. This retained interest, which is included in Accounts and Notes Receivable Trade in the Consolidated Balance Sheets, is recorded at fair value. Due to a short average collection cycle for such receivables, our collection experience history and the composition of the designated pool of trade accounts receivable that are part of this program, the fair value of our retained interest approximates the total amount of the designated pool of accounts receivable. CONSOL Energy will continue to service the sold trade receivables for the financial institutions for a fee based upon market rates for similar services. The cost of funds under this facility is based upon commercial paper rates, plus a charge for administrative services paid to the financial institutions. Costs associated with the receivables facility totaled $386 and $1,683 for the three and nine months ended September 30, 2011, respectively. Costs associated with the receivables facility totaled $863 and $1,868 for the three and nine months ended September 30, 2010, respectively. These costs have been recorded as financing fees which are included in Cost of Goods Sold and Other Operating Charges in the Consolidated Statements of Income. No servicing asset or liability has been recorded. The receivables facility expires in April 2012.
At September 30, 2011 and December 31, 2010, eligible accounts receivable totaled $200,000. There was subordinated retained interest of $200,000 at September 30, 2011 and there was no subordinated retained interest at December 31, 2010. There was no borrowings under the Securitization Facility recorded on the Consolidated Balance Sheet as of September 30, 2011. At December 31, 2010, $200,000 was recorded as Accounts Receivable – Securitization and Borrowings under the Securitization Facility on the Consolidated Balance Sheet based upon the borrowings outstanding at that date. For the nine months ended September 30, 2011 and 2010, the respective $200,000 decrease and $150,000 increase in the accounts receivable securitization program were reflected in Net Cash (Used in) provided by Financing Activities in the Consolidated Statement of Cash Flows. In accordance with the facility agreement, the Company is able to receive proceeds based upon the eligible accounts receivable at the previous month end.

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NOTE 8—PROPERTY, PLANT AND EQUIPMENT:

	September 30, 2011	December 31, 2010
Coal & other plant and equipment	$5,094,572	$5,100,085
Proven gas properties	1,507,682	1,662,605
Coal properties and surface lands	1,307,829	1,292,701
Unproven gas properties	1,280,354	2,206,399
Intangible drilling cost	1,234,529	1,116,884
Gas gathering equipment	925,668	941,772
Airshafts	660,324	662,315
Leased coal lands	540,051	536,603
Mine development	437,385	587,518
Coal advance mining royalties	395,362	389,379
Gas wells and related equipment	374,571	367,448
Other gas assets	74,981	84,571
Gas advance royalties	3,955	3,078
Total property, plant and equipment	13,837,263	14,951,358
Less Accumulated depreciation, depletion and amortization	4,766,163	4,822,107
Total Net Property, Plant and Equipment	$9,071,100	$10,129,251

Long-Lived Asset Abandonment
In June 2011, CONSOL Energy decided to permanently close its Mine 84 mining operation located near Washington, PA. This decision was part of CONSOL Energy's ongoing effort to reallocate resources into more profitable coal operations and Marcellus Shale drilling operations. The closure decision resulted in the recognition of an abandonment expense of $338 and $115,817 for the three and nine months ended September 30, 2011, respectively. The abandonment expense resulted from the removal of the June 30, 2011 carrying value of the following Mine 84 related assets from the Consolidated Balance Sheets: Mine development - $92,136, Airshafts - $15,352, Coal equipment - $2,080, Inventories - $757, and Prepaid Expenses - $385. Additionally, the Mine 84 abandonment expense also includes the recognition of a Mine Closing expense of $5,107. The effect on net income of the Mine 84 abandonment was $220 and $75,281 of expense for the three and nine months ended September 30, 2011, respectively. There was no impact to basic and dilutive earnings per share for the three months ended September 30, 2011. The impact to basic and dilutive earnings per share was $0.33 for the nine months ended September 30, 2011.

NOTE 9—SHORT-TERM NOTES PAYABLE:
On April 12, 2011, CONSOL Energy amended and extended its $1,500,000 Senior Secured Credit Agreement through April 12, 2016. The previous facility was set to expire on May 7, 2014. The amendment provides more favorable pricing and the facility continues to be secured by substantially all of the assets of CONSOL Energy and certain of its subsidiaries. CONSOL Energy's credit facility allows for up to $1,500,000 of borrowings and letters of credit. CONSOL Energy can request an additional $250,000 increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on a ratio of financial covenant debt to twelve-month trailing earnings before interest, taxes, depreciation, depletion and amortization (EBITDA), measured quarterly. The facility includes a minimum interest coverage ratio covenant of no less than 2.50 to 1.00, measured quarterly. The interest coverage ratio was 5.56 to 1.00 at September 30, 2011. The facility includes a maximum leverage ratio covenant of not more than 4.75 to 1.00, measured quarterly. The leverage ratio was 2.17 to 1.00 at September 30, 2011. The facility also includes a senior secured leverage ratio covenant of not more than 2.00 to 1.00, measured quarterly. The senior secured leverage ratio was 0.19 to 1.00 at September 30, 2011. Affirmative and negative covenants in the facility limit our ability to dispose of assets, make investments, purchase or redeem CONSOL Energy common stock, pay dividends, merge with another corporation and amend, modify or restate the senior unsecured notes. At September 30, 2011, the $1,500,000 facility

had no borrowings outstanding and $265,173 of letters of credit outstanding, leaving $1,234,827 of capacity available for borrowings and the issuance of letters of credit. The average interest rate for the three months and nine months ended September 30, 2011 was 4.15% and 4.07%, respectively. Accrued interest of $44 and $249 is included in Other Accrued Liabilities in the Consolidated Balance Sheets at September 30, 2011 and December 31, 2010, respectively.

On April 12, 2011, CNX Gas entered into a $1,000,000 Senior Secured Credit Agreement which extends until April 12, 2016. It replaced the $700,000 Senior Secured Credit Facility which was set to expire on May 6, 2014. The replacement facility provides more favorable pricing and the facility continues to be secured by substantially all of the assets of CNX Gas and its subsidiaries. CNX Gas' credit facility allows for up to $1,000,000 for borrowings and letters of credit. CNX Gas can request an additional $250,000 increase in the aggregate borrowing limit amount. The facility was increased to meet the asset development needs of the company. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. Covenants in the facility limit CNX Gas' ability to dispose of assets, make investments, pay dividends and merge with another corporation. The facility includes a maximum leverage ratio covenant of not more than 3.50 to 1.00, measured quarterly. The leverage ratio was 0.00 to 1.00 at September 30, 2011. The facility also includes a minimum interest coverage ratio covenant of no less than 3.00 to 1.00, measured quarterly. This ratio was 35.60 to 1.00 at September 30, 2011. At September 30, 2011, the $1,000,000 facility had no borrowings outstanding and $70,203 of letters of credit outstanding, leaving $929,797 of capacity available for borrowings and the issuance of letters of credit. The average interest rate for the three months and nine months ended September 30, 2011 was 1.89% and 2.08%, respectively. Accrued interest of $112 and $98 is included in Other Accrued Liabilities in the Consolidated Balance Sheets at September 30, 2011 and December 31, 2010, respectively.

NOTE 10—LONG-TERM DEBT:

	September 30, 2011	December 31, 2010
Debt:		
Senior notes due April 2017 at 8.00%, issued at par value	$1,500,000	$1,500,000
Senior notes due April 2020 at 8.25%, issued at par value	1,250,000	1,250,000
Senior notes due March 2021 at 6.375%, issued at par value	250,000	—
Senior secured notes due March 2012 at 7.875% (par value of $250,000 less unamortized discount of $242 at December 31, 2010)	—	249,758
Baltimore Port Facility revenue bonds in series due September 2025 at 5.75%	102,865	102,865
Advance royalty commitments (7.56% weighted average interest rate for September 30, 2011 and December 31, 2010)	32,211	32,211
Note Due December 2012 at 4.28%	—	10,438
Other long-term notes maturing at various dates through 2031	76	93
	3,135,152	3,145,365
Less amounts due in one year	11,718	16,629
Long-Term Debt	$3,123,434	$3,128,736

On March 9, 2011 CONSOL Energy closed the offering of $250,000 of 6.375% senior notes which mature on March 1, 2021. The notes are guaranteed by substantially all of our existing wholly owned domestic subsidiaries.

On April 11, 2011, CONSOL Energy redeemed all of its outstanding $250,000, 7.875% senior secured notes due March 1, 2012 in accordance with the terms of the indenture governing these notes. The redemption price included principal of $250,000, a make-whole premium of $15,785 and accrued interest of $2,188 for a total redemption cost of $267,973. The loss on extinguishment of debt was $16,090, which primarily represents the interest that would have been paid on these notes if held to maturity.

In August 2011, CONSOL Energy paid the remaining principal balance on the 4.28% Notes due December 2012. The early debt retirement was completed as a condition of a drilling services contract termination.

Transaction and financing fees of $14,907 were incurred in the three and nine months ended September 30, 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 of the indentures for each of those notes, clarifying that the transactions contemplated by the August 2011 Asset Acquisition

Agreements with Noble Energy and Hess Ohio Developments, LLC were permissible under those indentures. See Note 2—Acquisitions and Dispositions and Note 18—Subsequent Events for additional information.
Accrued interest related to Long-Term Debt of $113,575 and $64,009 was included in Other Accrued Liabilities in the Consolidated Balance Sheets at September 30, 2011 and December 31, 2010, respectively.

NOTE 11—COMMITMENTS AND CONTINGENCIES:
CONSOL Energy and its subsidiaries are subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations including environmental remediation, employment and contract disputes and other claims and actions arising out of the normal course of business. We accrue the estimated loss for these lawsuits and claims when the loss is probable and can be estimated. Our current estimated accruals related to these pending claims, individually and in the aggregate, are immaterial to the financial position, results of operations or cash flows of CONSOL Energy. It is possible that the aggregate loss in the future with respect to these lawsuits and claims could ultimately be material to the financial position, results of operations or cash flows of CONSOL Energy; however, such amount cannot be reasonably estimated. The amount claimed against CONSOL Energy is disclosed below when an amount is expressly stated in the lawsuit or claim, which is not often the case. The maximum aggregate amount claimed in those lawsuits and claims, regardless of probability, where a claim is expressly stated or can be estimated exceeds the aggregate amounts accrued for all lawsuits and claims by approximately $230,000.
The following lawsuits and claims include those for which a loss is probable and an accrual has been recognized.

American Electric Corp: On August 8, 2011, the United States Environmental Protection Agency, Region IV, sent Consolidation Coal Company a General Notice and Offer to Negotiate regarding the Ellis Road/American Electric Corp. Superfund Site in Jacksonville, Florida. The General Notice was sent to approximately 180 former customers of American Electric Corp. CONSOL Energy has confirmed that it did business with American Electric Corp. in 1983 84. The General Notice indicates that the EPA has determined that PCBs and other contaminants in the soils and sediments at and near the site require a removal action to address those areas. The Offer to Negotiate invites the potentially responsible parties (PRPs) to enter into an Administrative Settlement Agreement and Order on Consent to provide for conducting the removal action under the EPA oversight and to reimburse the EPA for its past costs, in the amount of $384 and for its future costs. CONSOL Energy has responded to the EPA indicating its willingness to participate in such negotiations, and CONSOL Energy is participating in the formation of a group of potentially responsible parties to consider conducting the removal action. The actual scope of the work has yet to be determined, and, therefore, CONSOL Energy is not able currently to estimate the total costs of the removal action or CONSOL Energy's likely share of such costs. However, given the available site background information and our experience in similar litigation, CONSOL Energy has estimated a range of potential liability and has established an initial accrual at the low end of the range. The liability is immaterial and is included in Other Accrued Liabilities on the Consolidated Balance Sheet.

Ward Transformer Superfund Site: CONSOL Energy was notified in November 2004 by the United States Environmental Protection Agency (EPA) that it is a potentially responsible party (PRP) under the Superfund program established by the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), with respect to the Ward Transformer site in Wake County, North Carolina. At that time, the EPA also identified 38 other PRPs for the Ward Transformer site. The EPA, CONSOL Energy and two other PRPs entered into an administrative Settlement Agreement and Order of Consent, requiring those PRPs to undertake and complete a PCB soil removal action, at and in the vicinity of the Ward Transformer property. Another party joined the participating PRPs and reduced CONSOL Energy's interim allocation share from 46% to 32%. In June 2008, while conducting the PCB soil excavation on the Ward property, it was determined that PCBs have migrated onto adjacent properties. The current estimated cost of remedial action for the area CONSOL Energy was originally named a PRP, including payment of the EPA's past and future cost, is approximately $65,000. The current estimated cost of the most likely remediation plan for the additional areas discovered is approximately $11,000. Also, in September 2008, the EPA notified CONSOL Energy and sixty other PRPs that there were additional areas of potential contamination allegedly related to the Ward Transformer Site. Current estimates of the cost or potential range of cost for this area are not yet available. There was no expense recognized in the three and nine months ended September 30, 2011 related to this matter. There was $2,880 of expense recognized in Cost of Goods Sold and Other Operating Charges in the three and nine months ended September 30, 2010 related to this matter. CONSOL Energy funded $250 in the nine months ended September 30, 2011 to an independent trust established for this remediation. CONSOL Energy funded $1,209 in the nine months ended September 30, 2010 to the trust. As of September 30, 2011, CONSOL Energy and the other participating PRPs had asserted CERCLA cost recovery and contribution claims against approximately 225 nonparticipating PRPs to recover a share of the costs incurred and to be incurred to conduct the removal actions at the Ward Site. CONSOL Energy's portion of recoveries from settled claims is $4,432. Accordingly, the liability reflected in Other Accrued Liabilities was reduced by these settled claims. The remaining net liability at September 30, 2011 is $3,528.

Asbestos-Related Litigation: One of our subsidiaries, Fairmont Supply Company (Fairmont), which distributes industrial supplies, currently is named as a defendant in approximately 7,500 asbestos-related claims in state courts in Pennsylvania, Ohio, West Virginia, Maryland, New Jersey, Texas and Illinois. This number has been reduced from the 22,500 pending claims

that were previously reported after a review of the dockets where these cases are pending found that approximately 15,000 cases had been dismissed by administrative order, without the payment of any damages or settlement amounts. 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. Based on over 15 years of experience with this litigation, we have established an accrual to cover our estimated liability for these cases. This accrual is immaterial and is included in Other Accrued Liabilities on the Consolidated Balance Sheet. Past payments by Fairmont with respect to asbestos cases have not been material; however, the aggregate amount claimed is not known at this time and the potential loss cannot be reasonably estimated because of the nature of the mass complaints, discovery is typically not permitted until shortly before the trial, and information regarding the identity and number of defendants for individual claims is not available until shortly before trial.
Severance Tax Litigation: In December 2010, Tazewell County, Virginia asserted a claim for the tax year 2007, although the County has not filed a lawsuit against CNX Gas Company LLC. The complaint alleged that CNX Gas' calculation of the license tax on the basis of the wellhead value (sales price less post production costs) rather than the sales price is improper. We continued to pay Tazewell County taxes based on our method of calculating the taxes. CONSOL Energy is evaluating the merits of that claim. The difference between the amount of tax that Tazewell County is claiming using its methodology for calculating the tax and the amount of tax as paid by CNX Gas Company is approximately $1,970 for January 1, 2007 through September 30, 2011. The related accrual is included in Other Liabilities on the Consolidated Balance Sheet.

Northern Appalachia Water Issues: In the Fall of 2009, a fish kill occurred in Dunkard Creek, which is a creek with segments in both Pennsylvania and West Virginia. The fish kill was caused by the growth of golden algae in the creek, which appears to be an invasive species. Our subsidiary, CCC, discharges treated mine water into Dunkard Creek from its Blacksville No. 2 Mine and from its Loveridge Mine. The discharges have levels of chlorides that cause Dunkard Creek to exceed West Virginia in-stream water quality standards. Prior to the fish kill and continuing thereafter, CCC was subject to an Agreed Order with the West Virginia Department of Environmental Protection (WVDEP) that set forth a schedule for compliance with these in-stream chloride limits. On December 18, 2009, the WVDEP issued a Unilateral Order that imposed additional conditions on CCC's discharges into Dunkard Creek and required CCC to develop a plan for long-term treatment of those and other high-chloride discharges. Pursuant to the Unilateral Order as well as a subsequent Unilateral Order issued by the WVDEP, CCC submitted a plan and schedule to WVDEP which provides for construction of a centralized advanced technology mine water treatment plant by May 31, 2013 to achieve compliance with chloride effluent limits and in-stream chloride water quality standards. The cost of the treatment plant and related facilities may reach or exceed $200,000. CCC negotiated a joint Consent Decree with the U.S. Environmental Protection Agency (EPA) and the WVDEP that includes a compliance plan and schedule. The Consent Decree, which was finalized in the three months ended December 31, 2010, included a civil penalty of $5,500, which was accrued at that time, to settle alleged past violations related to chlorides, without any admission of liability. CCC also negotiated a settlement with the WVDEP and the West Virginia Department of Natural Resources settling state claims for natural resource damages for $500 (which was accrued in the three months ended March 31, 2011), without any admission of liability. The civil penalty and the natural resource damage claim were paid in the nine months ended September 30, 2011. No additional penalties or damage claim remain related to this matter at September 30, 2011.
Decker/Gillingham Litigation: Two contractor employees-Messrs. Decker and Gillingham-were injured when a stairway affixed to the exterior of a building collapsed at CONSOL Energy's Research and Development facility in Allegheny County, Pennsylvania in 2007. Mr. Decker sustained a broken hip and leg. Mr. Gillingham sustained a torn

rotator cuff. Both men have recovered and are working, although both claim that the accident has limited their ability to perform their jobs. Messrs. Decker and Gillingham sued CONSOL Energy on June 4, 2008 and June 20, 2008, respectively, in Allegheny County Common Pleas Court, alleging, among other things, that CONSOL Energy was negligent in the maintenance of the stairway. The cases were consolidated. In late November, 2010, after a jury trial, the jury found that CONSOL Energy was negligent in maintaining the stairway and the jury awarded Mr. Decker and his spouse $5,000 and Mr. Gillingham and his spouse $2,800. These amounts included compensatory damages, as well as damages for pain and suffering, embarrassment and humiliation, and loss of ability to enjoy the pleasures of life. We have appealed the verdict. We have accrued $7,800 which was included in Other Accrued Liabilities for this claim. CONSOL Energy maintains insurance for damages in excess of $5,000 and has recognized a receivable of $2,826 in Other Receivables on the Consolidated Balance Sheet.

Royalty Owners Group Litigation: These five separate but related cases, filed on February 13, 2006 in the Circuit Court of Buchanan County, Virginia, involve claims by several of CNX Gas's lessors in southwest Virginia that certain improper deductions have been made on their royalty payments by CNX Gas with respect to the period from 1999 to the present. The deductions at issue primarily relate to post production expenses of gathering, compression and transportation. Specifically, the plaintiffs allege that (i) CNX Gas' gathering system in its Virginia field is over built, (ii) CNX Gas is not entitled to deductions for certain compression costs, because that is a production activity, not a post-production activity, and (iii) CNX Gas is not entitled to a deduction for firm transportation expense, because that is a marketing activity, not a post-production cost. The litigation has settled in the three months ended September 30, 2011, with the Company paying the lessors $1,000, which was previously accrued, and the Company will take a fixed deduction from royalties going forward.

The following lawsuits and claims include those for which a loss is possible, but not probable, and accordingly no accrual has been recognized.

Ryerson Dam Litigation: In 2008, the Pennsylvania Department of Conservation and Natural Resources (the Commonwealth) filed a six-count Complaint in the Court of Common Pleas of Allegheny County, Pennsylvania, claiming that the Company's underground longwall mining activities at its Bailey Mine caused cracks and seepage damage to the Ryerson Park Dam. The Commonwealth subsequently altered the dam, thereby eliminating the Ryerson Park Lake. The Commonwealth claimed that the Company is liable for dam reconstruction costs, lake restoration costs and natural resource damages totaling $58,000. The Court stayed the proceedings in the state court, holding that the Commonwealth should pursue administrative agency review of the claim. Furthermore, the Court found that the Commonwealth could not recover natural resource damages under applicable law. The Commonwealth then filed a subsidence-damage claim with the Pennsylvania Department of Environmental Protection (DEP) and the DEP reviewed the issue of whether the dam was damaged by subsidence. On February 16, 2010, the DEP issued its interim report, concluding that the alleged damage was subsidence related. In the next phase of the DEP proceeding, which was the damage phase, the DEP determined that the Company must repair the dam. The DEP estimated the cost of repair to be approximately $20,000. The Company has appealed the DEP's findings to the Pennsylvania Environmental Hearing Board (PEHB), which will consider the case de novo, meaning without regard to the DEP's decision, as to any finding of causation of damage and/or the amount of damages. In order to perfect its appeal to the PEHB under the applicable statute, the Company deposited $20,291 into escrow as security for the DEP's estimated cost of repair. This amount is reflected as restricted cash on the Consolidated Balance Sheets at September 30, 2011 and December 31, 2010. The Company is seeking to substitute an appeal bond for the cash deposit. Either party may appeal the decision of the PEHB to the Pennsylvania Commonwealth Court, and then, as may be allowed, to the Pennsylvania Supreme Court. On March 31, 2011, the DEP informed the parties that it was withdrawing its Order requiring the Company to repair the dam because of additional movements of the dam site, well after mining had ceased; therefore, that movement would preclude repair of the dam as a remedy. On May 18, 2011, the DEP attempted to reinstate its order requiring repair of the dam. The Company filed a motion to vacate that order, arguing that the DEP cannot reinstate an order which was withdrawn in the manner in which the DEP attempted to do so. The PEHB ruled that DEP could reinstate its November 3, 2010 order and issued a scheduling order. The discovery period runs until October 16, 2012, with summary judgment motions due in January 2013. A hearing on the merits will not occur until sometime in the spring or summer of 2013. As to the underlying claim, the Company believes it is not responsible for the damage to the dam and that numerous grounds exist upon which to attack the propriety of the claims. For that reason, we have not accrued a liability for this claim; however, if the Company is ultimately found to be liable for damages to the dam, we believe the range of loss would be between $9,000 and $30,000.

South Carolina Gas & Electric Company Arbitration: South Carolina Electric & Gas Company (SCE&G), a utility, has demanded arbitration, seeking $36,000 in damages against CONSOL of Kentucky and CONSOL Energy Sales Company. SCE&G claims it suffered damages in obtaining cover coal to replace coal which was not delivered in 2008 under a coal sales agreement. The Company counterclaimed against SCE&G for $9,400 for terminating coal shipments under the sales agreement which SCE&G had agreed could be made up in 2009. A hearing on the claims is scheduled for October 2011. The named CONSOL Energy defendants deny all liability and intend to vigorously defend the action filed against them. For that reason, we have not accrued a liability for this claim. If the named CONSOL Energy defendants prevail, the range of recovery would be between $5,100 and $6,800. If liability is ultimately imposed on the named CONSOL Energy defendants, we believe the range of loss would be between

$16,000 and $27,000.

CNX Gas Shareholders Litigation: CONSOL Energy has been named as a defendant in five putative class actions brought by alleged shareholders of CNX Gas challenging the tender offer by CONSOL Energy to acquire all of the shares of CNX Gas common stock that CONSOL Energy did not already own for $38.25 per share. The two cases filed in Pennsylvania Common Pleas Court have been stayed and the three cases filed in the Delaware Chancery Court have been consolidated under the caption In Re CNX Gas Shareholders Litigation (C.A. No. 5377-VCL). With one exception, these cases also name CNX Gas and certain officers and directors of CONSOL Energy and CNX Gas as defendants. All five actions generally allege that CONSOL Energy breached and/or aided and abetted in the breach of fiduciary duties purportedly owed to CNX Gas public shareholders, essentially alleging that the $38.25 per share price that CONSOL Energy paid to CNX Gas shareholders in the tender offer and subsequent short-form merger was unfair. Among other things, the actions sought a permanent injunction against or rescission of the tender offer, damages, and attorneys' fees and expenses. The Delaware Court of Chancery denied an injunction against the tender offer and CONSOL Energy completed the acquisition of the outstanding shares of CNX Gas on June 1, 2010. The Delaware Court of Chancery certified to the Delaware Supreme Court the question of what legal standard should be applied to the tender offer, which would effectively determine whether the shareholders can proceed with a damage claim. The Delaware Supreme Court declined to accept the appeal pending a final judgment. Therefore, the lawsuit will likely go to trial, possibly later in 2011. There may be mediation prior to any trial. CONSOL Energy believes that these actions are without merit and intends to defend them vigorously. For that reason, we have not accrued a liability for this claim; however, if liability is ultimately imposed, based on the expert reports that have been exchanged by the parties, we believe the range of loss would be up to $221,000.

Rasnake Litigation: On August 28, 2006, plaintiffs filed a complaint in Russell County Circuit Court of Lebanon, Virginia, involving the CBM located on four separate tracts of land located in Russell and Buchanan Counties, Virginia (the “Subject Property”). Plaintiffs allege that CNX Gas is trespassing upon the Subject Property by producing CBM therefrom without authorization. Plaintiffs also allege that CNX Gas has committed slander on plaintiffs' title by failing to properly recognize their ownership interest in the Subject Property when submitting pooling applications to the Virginia Gas and Oil Board. The plaintiffs seek trespass damages in an amount equal to the total revenue from the wells. We believe that their trespass claim is without merit because we produced the gas pursuant to a force pooling order from the Virginia Gas and Oil Board and we believe total revenue is not the proper remedy for trespass damages. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. For that reason, we have not accrued a liability for this claim, however, if liability is ultimately imposed, we believe the range of loss would be between $500 and $2,000.

The following royalty and land right lawsuits and claims include those for which a loss is possible, but not probable, and accordingly, no accrual has been recognized. These claims are influenced by many factors which prevent the estimation of a range of potential loss. These factors include, but are not limited to, generalized allegations of unspecified damages (such as improper deductions), discovery having not commenced or not having been completed, unavailability of expert reports on damages and non-monetary issues are being tried. For example, in instances where a gas lease termination is sought, damages would depend on speculation as to if and when the gas production would otherwise have occurred, how many wells would have been drilled on the lease premises, what their production would be, what the cost of production would be, and what the price of gas would be during the production period. An estimate is calculated, if applicable, when sufficient information becomes available.

C. L. Ritter: On March 1, 2011, the Company was served with a complaint instituted by C. L. Ritter Lumber Company Incorporated against Consolidation Coal Company (CCC), Island Creek Coal Company, (ICCC), CNX Gas Company LLC, subsidiaries of CONSOL Energy Inc., as well as CONSOL Energy itself in the Circuit Court of Buchanan County, Virginia, seeking damages and injunctive relief in connection with the deposit of untreated water from mining activities at CCC's Buchanan Mine into nearby void spaces at one of the mines of ICCC. The suit alleges damages of up to $300,000 for alleged damage to coal and coalbed methane, as well as breach of contract damages. We have removed the case to federal court and filed a motion to dismiss, largely predicated on the statute of limitations bar. The Magistrate Judge recommended denying the motion to dismiss largely based on the plaintiff's failure to plead when the water depositing was discovered and because the plaintiff was claiming under CERCLA. We filed objections to those Recommendations. The trial judge ruled that the issue of the applicability of the statute of limitations bar can only be addressed after discovery. Three similar lawsuits were filed recently in the same court by other plaintiffs; the Company intends to file motions to dismiss those suits as well. CCC believes that it had, and continues to have, the right to store water in these void areas. CCC and the other named CONSOL Energy defendants deny all liability and intend to vigorously defend the action filed against them in connection with the removal and deposit of water from the Buchanan Mine. Consequently, we have not recognized any liability related to these actions.

Hale Litigation: A purported class action lawsuit was filed on September 23, 2010 in U.S. District Court in Abingdon, Virginia styled Hale v. CNX Gas Company LLC et. al. The lawsuit alleges that the plaintiff class consists of oil and gas owners, that the Virginia Supreme Court has decided that coalbed methane (CBM) belongs to the owner of the oil and gas estate, that the Virginia Gas and Oil Act of 1990 unconstitutionally allows force pooling of CBM, that the Act unconstitutionally provides only a 1/8 royalty to CBM owners for gas produced under the force pooling orders, and that the Company only relied upon control of the coal estate in force pooling the CBM notwithstanding the Virginia Supreme Court decision holding that if only the coal estate is controlled, the CBM is not thereby controlled. The lawsuit seeks a judicial declaration of ownership of the CBM and that the entire net proceeds of CBM production (that is, the 1/8 royalty and the 7/8 of net revenues since production began) be distributed to the class members. The Magistrate Judge issued a Report and Recommendation in which she recommended that the District Judge decide that the deemed lease provision of the Gas and Oil Act is constitutional as is the 1/8 royalty, and that CNX Gas need not distribute the net proceeds to class members. The Magistrate Judge recommended against the dismissal of certain other claims, none of which are believed to have any significance. Both parties objected to the portions of the Recommendations which adversely affected their interests. The District Judge affirmed the Magistrate Judge's Recommendations in their entirety. The plaintiffs and CNX Gas have agreed to stay this litigation. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. Consequently, we have not recognized any liability related to these actions.

Addison Litigation: A purported class action lawsuit was filed on April 28, 2010 in Federal court in Virginia styled Addison v. CNX Gas Company LLC. The case involves two primary claims: (i) the plaintiff and similarly situated CNX Gas lessors identified as conflicting claimants during the force pooling process before the Virginia Gas and Oil Board are the owners of the CBM and, accordingly, the owners of the escrowed royalty payments being held by the Commonwealth of Virginia; and (ii) CNX Gas failed to either pay royalties due these conflicting claimant lessors or paid them less than required because of the alleged practice of improper below market sales and/or taking alleged improper post-production deductions. Plaintiffs seek a declaratory judgment regarding ownership and compensatory and punitive damages for breach of contract; conversion; negligence (voluntary undertaking), for force pooling coal owners after the Ratliff decision declared coal owners did not own the CBM; negligent breach of duties as an operator; breach of fiduciary duties; and unjust enrichment. We filed a Motion to Dismiss in this case, and the Magistrate Judge recommended dismissing some claims and allowing others to proceed. Both parties objected to the portions of the Recommendations which adversely affected their interests. Oral argument on the objections occurred on August 2, 2011 before the District Judge, who affirmed the Magistrate Judge's Recommendations in their entirety. The plaintiffs and CNX Gas have agreed to stay this litigation. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. Consequently, we have not recognized any liability related to these actions.

Hall Litigation: A purported class action lawsuit was filed on December 23, 2010 styled Hall v. CONSOL Gas Company in Allegheny County Pennsylvania Common Pleas Court. The named plaintiff is Earl D. Hall. The purported class plaintiffs are all Pennsylvania oil and gas lessors to Dominion Exploration and Production Company, whose leases were acquired by CONSOL Energy. The complaint alleges more than 1,000 similarly situated lessors. The lawsuit alleges that CONSOL Energy incorrectly calculated royalties by (i) calculating line loss on the basis of allocated volumes rather than on a well-by-well basis, (ii) possibly calculating the royalty on the basis of an incorrect price, (iii) possibly taking unreasonable deductions for post-production costs and costs that were not arms-length, (iv) not paying royalties on gas lost or used before the point of sale, and (v) not paying royalties on oil production. The complaint also alleges that royalty statements were false and misleading. The complaint seeks damages, interest and an accounting on a well-by-well basis. The plaintiff amended the complaint and we have filed preliminary objections. In response to our preliminary objections, the Court dismissed the plaintiffs' claims for underpayment of royalties on gas lost or used before the point of sale and allowed the plaintiffs to amend their complaint to specifically state their claim on oil production. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. Consequently, we have not recognized any liability related to these actions.

Kennedy Litigation: The Company is a party to a case filed on March 26, 2008 captioned Earl Kennedy (and others) v. CNX Gas and CONSOL Energy in the Court of Common Pleas of Greene County, Pennsylvania. The lawsuit alleges that CNX Gas and CONSOL Energy trespassed and converted gas and other minerals allegedly belonging to the plaintiffs in connection with wells drilled by CNX Gas. The complaint, as amended, seeks injunctive relief, including removing CNX Gas from the property, and compensatory damages of $20,000. The suit also sought to overturn existing law as to the ownership of coalbed methane in Pennsylvania, but that claim was dismissed by the court; the plaintiffs are seeking to appeal that dismissal. The suit also seeks a determination that the Pittsburgh 8 coal seam does not include the “roof/rider” coal. The court denied the plaintiff's summary judgment motion on that issue. The court will hold a bench trial on the “roof/rider” coal issue in November 2011. CNX Gas and CONSOL Energy believe this lawsuit to be without merit and intend to vigorously defend it. Consequently, we have not recognized any liability related to these actions.

Rowland Litigation: Rowland Land Company filed a complaint in May 2011 against CONSOL Energy, CNX Gas, Dominion Resources, and EQT Production Company (EQT) in Raleigh County Circuit Court, West Virginia. Rowland is the lessor on a 33,000 acre oil and gas lease in southern West Virginia. EQT was the original lessee, but they farmed out the development of the lease to Dominion, in exchange for an overriding royalty. Dominion sold the indirect subsidiary that held the lease to a subsidiary of CONSOL Energy on April 30, 2010. Subsequent to that acquisition, the subsidiary that held the lease was merged into CNX Gas as part of an internal reorganization. Rowland alleges that (i) Dominion's sale of the subsidiary to CONSOL Energy was a change in control that required its consent under the terms of the farmout agreement and lease, and (ii) the subsequent merger of the subsidiary into CNX Gas was an assignment that required its consent under the lease. Rowland alleges that the failure to obtain the required consent constitutes a breach of the lease and it seeks damages and a forfeiture of the lease. CONSOL Energy and CNX Gas have filed a motion to dismiss the complaint, arguing among other things, that Dominion's sale of the indirect subsidiary was not a change in control; that even if the sale constituted a change in control, the purchase agreement between Dominion and CONSOL Energy did not give effect to the transfer so the transfer never occurred; that the mergers did not require consent; and that Rowland did not provide timely notice of breach of the lease in accordance with its terms. Rowland is amending its complaint to include allegations that CONSOL Energy and Dominion Resources are liable for their subsidiaries' actions. We will file a motion to dismiss in response. CONSOL Energy believes that the case is without merit and intends to defend it vigorously. Consequently, we have not recognized any liability related to these actions.

Majorsville Storage Field Declaratory Judgment: On March 3, 2011, an attorney sent a letter to CNX Gas regarding certain leases that CNX Gas obtained from Columbia Gas in Greene County, Pennsylvania involving the Majorsville Storage Field. The letter was written on behalf of three lessors alleging that the leases totaling 525 acres are invalid, and had expired by their terms. The plaintiffs' theory is that the rights of storage and production are severable under the leases. Ignoring the fact that the leases have been used for gas storage, they claim that since there has been no production or development of production, the right to produce gas expired at the end of the primary terms. On June 16, 2011 in the Court of Common Pleas of Greene County, Pennsylvania, the Company filed a declaratory judgment action, seeking to have a court confirm the validity of the leases. We believe that we will prevail in this litigation based on the language of the leases and the current status of the law. Consequently, we have not recognized any liability related to these actions.

The following lawsuit and claims include those for which a loss is remote and accordingly, no accrual has been recognized, although if a non favorable verdict were received the impact could be material

Comer Litigation: In 2005, plaintiffs Ned Comer and others filed a purported class action lawsuit in the U.S. District Court for the Southern District of Mississippi against a number of companies in energy, fossil fuels and chemical industries, including CONSOL Energy styled, Comer, et al. v. Murphy Oil, et al. The plaintiffs, residents and owners of property along the Mississippi Gulf coast, alleged that the defendants caused the emission of greenhouse gases that contributed to global warming, which in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina, which combined to destroy the plaintiffs' property. The District Court dismissed the case and the plaintiffs appealed. The Circuit Court panel reversed and the defendants sought a rehearing before the entire court. A rehearing before the entire court was granted, which had the effect of vacating the panel's reversal, but before the case could be heard on the merits, a number of judges recused themselves and there was no longer a quorum. As a result, the District Court's dismissal was effectively reinstated. The plaintiffs asked the U.S. Supreme Court to require the Circuit Court to address the merits of their appeal. On January 11, 2011, the Supreme Court denied that request. Although that should have resulted in the dismissal being a finality, the plaintiffs filed a lawsuit on May 27, 2011, in the same jurisdiction against essentially the same defendants making nearly identical allegations as in the original lawsuit. The defendants intend to seek an early dismissal of the case.

At September 30, 2011, CONSOL Energy has provided the following financial guarantees, unconditional purchase obligations and letters of credit to certain third parties, as described by major category in the following table. These amounts represent the maximum potential total of future payments that we could be required to make under these instruments. These amounts have not been reduced for potential recoveries under recourse or collateralization provisions. Generally, recoveries under reclamation bonds would be limited to the extent of the work performed at the time of the default. No amounts related to these financial guarantees and letters of credit are recorded as liabilities on the financial statements. CONSOL Energy management believes that these guarantees will expire without being funded, and therefore the commitments will not have a material adverse effect on financial condition.

	Amount of Commitment Expiration Per Period				
	Total Amounts Committed	Less Than 1 Year	1-3 Years	3-5 Years	Beyond 5 Years
Letters of Credit:					
Employee-Related	$197,947	$90,573	$107,374	$—	$—
Environmental	56,994	55,266	1,728	—	—
Gas	70,213	14,913	55,300	—	—
Other	10,305	164	10,141	—	—
Total Letters of Credit	335,459	160,916	174,543	—	—
Surety Bonds:					
Employee-Related	204,895	204,895	—	—	—
Environmental	434,621	434,251	370	—	—
Gas	9,872	9,806	65	—	1
Other	17,456	17,456	—	—	—
Total Surety Bonds	666,844	666,408	435	—	1
Guarantees:					
Coal	73,462	44,994	22,968	1,000	4,500
Gas	105,346	52,239	22,485	—	30,622
Other	374,311	72,335	120,230	72,514	109,232
Total Guarantees	553,119	169,568	165,683	73,514	144,354
Total Commitments	$1,555,422	$996,892	$340,661	$73,514	$144,355

Employee-related financial guarantees have primarily been provided to support the United Mine Workers' of America's 1992 Benefit Plan and various state workers' compensation self-insurance programs. Environmental financial guarantees have primarily been provided to support various performance bonds related to reclamation and other environmental issues. Gas financial guarantees have primarily been provided to support various performance bonds related to land usage and restorative issues. Other guarantees have been extended to support insurance policies, legal matters and various other items necessary in the normal course of business. Other guarantees have also been provided to promise the full and timely payments to lessors of mining equipment and support various other items necessary in the normal course of business.

CONSOL Energy and CNX Gas enter into long-term unconditional purchase obligations to procure major equipment purchases, natural gas firm transportation, gas drilling services and other operating goods and services. These purchase obligations are not recorded on the Consolidated Balance Sheet. As of September 30, 2011, the purchase obligations for each of the next five years and beyond were as follows:

Obligations Due	Amount
Less than 1 year	$228,316
1 - 3 years	343,911

3 - 5 years	388,838
More than 5 years	1,855,746
Total Purchase Obligations	$2,816,811

Costs related to these purchase obligations include:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Major equipment purchases	$12,889	$10,687	$30,066	$37,835
Firm transportation expense	15,225	9,021	43,359	25,124
Gas drilling obligations	24,423	5,934	74,587	6,564
Other	65	265	256	597
Total costs related to purchase obligations	$52,602	$25,907	$148,268	$70,120

NOTE 12—DERIVATIVE INSTRUMENTS:

CONSOL Energy enters into financial derivative instruments to manage our exposure to commodity price volatility. We measure each derivative instrument at fair value and record it on the balance sheet as either an asset or liability. Changes in the fair value of the derivatives are recorded currently in earnings unless special hedge accounting criteria are met. For derivatives designated as fair value hedges, the changes in fair value of both the derivative instrument and the hedged item are recorded in earnings. For derivatives designated as cash flow hedges, the effective portions of changes in fair value of the derivative are reported in Other Comprehensive Income or Loss (OCI) and reclassified into earnings in the same period or periods which the forecasted transaction affects earnings. The ineffective portions of hedges are recognized in earnings in the current period. CONSOL Energy currently utilizes only cash flow hedges that are considered highly effective.

CONSOL Energy formally assesses both at inception of the hedge and on an ongoing basis whether each derivative is highly effective in offsetting changes in the fair values or the cash flows of the hedged item. If it is determined that a derivative is not highly effective as a hedge or if a derivative ceases to be a highly effective hedge, CONSOL Energy will discontinue hedge accounting prospectively.

CONSOL Energy is exposed to credit risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is subject to continuing review. The Company has not experienced any issues of non-performance by derivative counterparties.

CONSOL Energy has entered into swap contracts for natural gas to manage the price risk associated with the forecasted natural gas revenues. The objective of these hedges is to reduce the variability of the cash flows associated with the forecasted revenues from the underlying commodity. As of September 30, 2011, the total notional amount of the Company’s outstanding natural gas swap contracts was 177.5 billion cubic feet. These swap contracts are forecasted to settle through December 31, 2014 and meet the criteria for cash flow hedge accounting. During the next twelve months, $56,720 of unrealized gain is expected to be reclassified from Other Comprehensive Income and into earnings, as a result of the settlement of cash flow hedges. No gains or losses have been reclassified into earnings as a result of the discontinuance of cash flow hedges.

The fair value at September 30, 2011 of CONSOL Energy's derivative instruments, which were all natural gas swaps and qualify as cash flow hedges, was an asset of $136,006 and a liability of $1,002. The total asset is comprised of $93,243 and $42,763 which were included in Prepaid Expense and Other Assets, respectively, on the Consolidated Balance Sheets. The total liability is included in Other Liabilities on the Consolidated Balance Sheets.

The effect of derivative instruments on the Consolidated Statements of Income for the three months ended September 30, 2011 is as follows:

Derivative in Cash Flow Hedging Relationship	Amount of Gain Recognized in OCI on Derivative	Location of Gain Reclassified from Accumulated	Amount of Gain Reclassified from Accumulated	Location of Gain Recognized in Income on	Amount of Gain Recognized in Income on Derivative

	2011	OCI into Income	OCI into Income 2011	Derivative	2011
Natural Gas Price Swaps	$59,953	Outside Sales	$20,974	Outside Sales	$333
Total	$59,953		$20,974		$333

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The effect of derivative instruments on the Consolidated Statements of Income for the nine months ended September 30, 2011 is as follows:

Derivative in Cash Flow Hedging Relationship	Amount of Gain Recognized in OCI on Derivative 2011	Location of Gain Reclassified from Accumulated OCI into Income	Amount of Gain Reclassified from Accumulated OCI into Income 2011	Location of Gain Recognized in Income on Derivative	Amount of Gain Recognized in Income on Derivative 2011
Natural Gas Price Swaps	$92,718	Outside Sales	$56,719	Outside Sales	$297
Total	$92,718		$56,719		$297

The fair value at December 31, 2010 of CONSOL Energy's derivative instruments, which were all natural gas swaps and qualify as cash flow hedges, was an asset of $79,960 and a liability of $3,720. The total asset is comprised of $52,022 and $27,938 which were included in Prepaid Expense and Other Assets, respectively, on the Consolidated Balance Sheets. The total liability is comprised of $3,191 and $529 which were included in Other Accrued Liabilities and Other Liabilities, respectively, on the Consolidated Balance Sheets.

The effect of derivative instruments on the Consolidated Statements of Income for the three months ended September 30, 2010 is as follows:

Derivative in Cash Flow Hedging Relationship	Amount of Gain Recognized in OCI on Derivative 2010	Location of Gain Reclassified from Accumulated OCI into Income	Amount of Gain Reclassified from Accumulated OCI into Income 2010	Location of (Loss) Recognized in Income on Derivative	Amount of (Loss) Recognized in Income on Derivative 2010
Natural Gas Price Swaps	$43,367	Outside Sales	$40,711	Outside Sales	$(98)
Total	$43,367		$40,711		$(98)

The effect of derivative instruments on the Consolidated Statements of Income for the nine months ended September 30, 2010 is as follows:

Derivative in Cash Flow Hedging Relationship	Amount of Gain Recognized in OCI on Derivative 2010	Location of Gain Reclassified from Accumulated OCI into Income	Amount of Gain Reclassified from Accumulated OCI into Income 2010	Location of Gain Recognized in Income on Derivative	Amount of Gain Recognized in Income on Derivative 2010
Natural Gas Price Swaps	$132,895	Outside Sales	$138,645	Outside Sales	$50
Total	$132,895		$138,645		$50

NOTE 13—OTHER COMPREHENSIVE LOSS:

Total comprehensive income (loss), net of tax, for the nine months ended September 30, 2011 is as follows:

	Treasury Rate Lock	Change in Fair Value of Cash Flow Hedges	Adjustments for Actuarially Determined Liabilities	Accumulated Other Comprehensive Loss
Balance at December 31, 2010	$96	$46,087	$(920,521)	$(874,338)
Net increase in value of cash flow hedge	—	92,718	—	92,718
Reclassification of cash flow hedges from other comprehensive income to earnings	—	(57,016)	—	(57,016)
Current period change	(96)	—	37,836	37,740
Balance at September 30, 2011	$—	$81,789	$(882,685)	$(800,896)

NOTE 14—FAIR VALUE OF FINANCIAL INSTRUMENTS:

The financial instruments measured at fair value on a recurring basis are summarized below:

Description	Fair Value Measurements at September 30, 2011			Fair Value Measurements at December 31, 2010		
	Quoted Prices in Active Markets for Identical Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Quoted Prices in Active Markets for Identical Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Gas Cash Flow Hedges	$—	$135,004	$—	$—	$76,240	$—

The following methods and assumptions were used to estimate the fair value for which the fair value option was not elected:

Cash and cash equivalents: The carrying amount reported in the balance sheets for cash and cash equivalents approximates its fair value due to the short-term maturity of these instruments.

Restricted cash: The carrying amount reported in the balance sheets for restricted cash approximates its fair value due to the short-term maturity of these instruments.

Short-term notes payable: The carrying amount reported in the balance sheets for short-term notes payable approximates its fair value due to the short-term maturity of these instruments.

Borrowings under Securitization Facility: The carrying amount reported in the balance sheets for borrowings under the securitization facility approximates its fair value due to the short-term maturity of these instruments.

Long-term debt: The fair value of long-term debt is measured using unadjusted quoted market prices or estimated using discounted cash flow analyses. The discounted cash flow analyses are based on current market rates for instruments with similar cash flows.

The carrying amounts and fair values of financial instruments for which the fair value option was not elected are as follows:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$472,523	$472,523	$32,794	$32,794
Restricted cash	$20,291	$20,291	$20,291	$20,291
Short-term notes payable	$—	$—	$(284,000)	$(284,000)

Borrowings under Securitization Facility	$—	$—	$(200,000)	$(200,000)
Long-term debt	$(3,135,152)	$(3,282,549)	$(3,145,365)	$(3,341,406)

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NOTE 15—SEGMENT INFORMATION:

CONSOL Energy has two principal business divisions: Coal and Gas. The principal activities of the Coal division are mining, preparation and marketing of steam coal, sold primarily to power generators, and metallurgical coal, sold to metal and coke producers. The Coal division includes four reportable segments. These reportable segments are Steam, Low Volatile Metallurgical, High Volatile Metallurgical and Other Coal. Each of these reportable segments includes a number of operating segments (mines or type of coal sold). For the three and nine months ended September 30, 2011, the Steam aggregated segment includes the following mines: Bailey, Blacksville #2, Enlow Fork, Fola Complex, Loveridge, McElroy, Miller Creek Complex, Robinson Run and Shoemaker. For the three and nine months ended September 30, 2011, the Low Volatile Metallurgical aggregated segment includes the Buchanan Mine. For the three and nine months ended September 30, 2011, the High Volatile Metallurgical aggregated segment includes: Bailey, Blacksville #2, Enlow Fork, Fola Complex, Loveridge, Miller Creek Complex and Robinson Run coal sales. The Other Coal segment includes our purchased coal activities, idled mine activities, as well as various other activities assigned to the Coal division but not allocated to each individual mine. The principal activity of the Gas division is to produce pipeline quality natural gas for sale primarily to gas wholesalers. The Gas division includes four reportable segments. These reportable segments are Coalbed Methane, Marcellus, Conventional and Other Gas. The Other Gas segment includes our purchased gas activities as well as various other activities assigned to the Gas division but not allocated to each individual well type. CONSOL Energy’s All Other segment includes terminal services, river and dock services, industrial supply services and other business activities. Intersegment sales have been recorded at amounts approximating market. Operating profit for each segment is based on sales less identifiable operating and non-operating expenses.

Industry segment results for three months ended September 30, 2011 are:

	Steam	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Conventional Gas	Other Gas	Total Gas	Al Ot
Sales—outside	$732,135	$307,969	$83,065	$12,593	$1,135,762	$116,954	$39,036	$38,974	$3,410	$198,374	$8
Sales—purchased gas	—	—	—	—	—	—	—	—	1,155	1,155	—
Sales—gas royalty interests	—	—	—	—	—	—	—	—	17,083	17,083	—
Freight—outside	—	—	—	59,871	59,871	—	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	726	726	49
Total Sales and Freight	$732,135	$307,969	$83,065	$72,464	$1,195,633	$116,954	$39,036	$38,974	$22,374	$217,338	$1
Earnings (Loss) Before Income Taxes	$83,505	$200,742	$24,091	$(40,061)	$268,277	$39,522	$11,723	$(8,602)	$(42,074)	$569	$9
Segment assets					$5,131,432					$5,959,480	$3
Depreciation, depletion and amortization					$96,797					$58,131	$4
Capital expenditures					$182,588					$215,830	$1

(A) Includes equity in earnings of unconsolidated affiliates of $4,842, $693 and $3,142 for Coal, Gas and All Other, respectively.

(B) Includes investments in unconsolidated equity affiliates of $33,037, $91,853 and $50,928 for Coal, Gas and All Other, respectively.

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Industry segment results for three months ended September 30, 2010 are:

	Steam	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Conventional Gas	Other Gas	Total Gas	Al Ot
Sales—outside	$740,612	$215,394	$22,208	$3,337	$981,551	$140,801	$15,572	$45,254	$1,975	$203,602	$7
Sales—purchased gas	—	—	—	—	—	—	—	—	3,524	3,524	—
Sales—gas royalty interests	—	—	—	—	—	—	—	—	18,131	18,131	—
Freight—outside	—	—	—	37,269	37,269	—	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	852	852	42
Total Sales and Freight	$740,612	$215,394	$22,208	$40,606	$1,018,820	$140,801	$15,572	$45,254	$24,482	$226,109	$1
Earnings (Loss) Before Income Taxes	$68,497	$135,171	$11,599	$(96,684)	$118,583	$59,259	$2,591	$(2,389)	$(23,938)	$35,523	$8
Segment assets					$4,948,966					$5,868,941	$3
Depreciation, depletion and amortization					$98,101					$58,909	$4
Capital expenditures					$132,847					$102,235	$7

(C) Includes equity in earnings of unconsolidated affiliates of $4,142, $785 and $1,976 for Coal, Gas and All Other, respectively.

(D) Includes investments in unconsolidated equity affiliates of $20,472, $24,651 and $47,138 for Coal, Gas and All Other, respectively.

Industry segment results for nine months ended September 30, 2011 are:

	Steam	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Conventional Gas	Other Gas	Total Gas
Sales—outside	$2,315,467	$824,035	$278,986	$59,465	$3,477,953	$346,713	$88,316	$119,899	$8,696	$563,624
Sales—purchased gas	—	—	—	—	—	—	—	—	3,297	3,297
Sales—gas royalty interests	—	—	—	—	—	—	—	—	52,191	52,191
Freight—outside	—	—	—	156,311	156,311	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	2,648	2,648
Total Sales and Freight	$2,315,467	$824,035	$278,986	$215,776	$3,634,264	$346,713	$88,316	$119,899	$66,832	$621,760
Earnings (Loss) Before Income Taxes	$372,653	$524,855	$111,012	$(289,401)	$719,119	$119,092	$24,605	$(14,434)	$(76,272)	$52,991
Segment assets					$5,131,432					$5,959,48
Depreciation, depletion and amortization					$293,793					$159,109
Capital expenditures					$435,818					$535,067

(E) Includes equity in earnings of unconsolidated affiliates of $13,544, $1,694 and $4,751 for Coal, Gas and All Other, respectively.

(F) Includes investments in unconsolidated equity affiliates of $33,037, $91,853 and $50,928 for Coal, Gas and All Other, respectively.

Industry segment results for nine months ended September 30, 2010 are:

	Steam	Low Volatile Metallurgical	High Volatile Metallurgical	Other Coal	Total Coal	Coalbed Methane	Marcellus Shale	Conventional Gas	Other Gas	Total Gas
Sales—outside	$2,202,931	$490,996	$135,230	$32,498	$2,861,655	$451,149	$33,956	$78,005	$5,068	$568,178
Sales—purchased gas	—	—	—	—	—	—	—	—	8,280	8,280
Sales—gas royalty interests	—	—	—	—	—	—	—	—	46,621	46,621
Freight—outside	—	—	—	96,544	96,544	—	—	—	—	—
Intersegment transfers	—	—	—	—	—	—	—	—	2,413	2,413
Total Sales and Freight	$2,202,931	$490,996	$135,230	$129,042	$2,958,199	$451,149	$33,956	$78,005	$62,382	$625,492
Earnings (Loss) Before Income Taxes	$316,228	$268,547	$70,563	$(306,170)	$349,168	$211,179	$4,953	$998	$(53,729)	$163,401
Segment assets					$4,948,966					$5,868,941
Depreciation, depletion and amortization					$259,849					$139,954
Capital expenditures					$517,515					$3,766,694

(G) Includes equity in earnings of unconsolidated affiliates of $10,570, $61 and $4,964 for Coal, Gas and All Other, respectively.

(H) Includes investments in unconsolidated equity affiliates of $20,472, $24,651 and $47,138 for Coal, Gas and All Other, respectively.

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Reconciliation of Segment Information to Consolidated Amounts:
Earnings Before Income Taxes:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Segment Earnings Before Income Taxes for total reportable business segments	$268,846	$154,106	$772,110	$512,569
Segment Earnings Before Income Taxes for all other businesses	9,561	8,853	12,134	18,477
Interest income (expense), net and other non-operating activity (I)	(61,167)	(69,819)	(197,792)	(139,092)
Transaction and Financing Fees (I)	(14,907)	(334)	(14,907)	(61,084)
Evaluation fees for non-core asset dispositions (I)	(1,911)	(1,788)	(5,172)	(1,788)
Loss on debt extinguishment	—	—	(16,090)	—
Operating lease cease-use	—	122	—	374
Earnings Before Income Taxes	$200,422	$91,140	$550,283	$329,456

Total Assets:	September 30, 2011	2010
Segment assets for total reportable business segments	$11,090,912	$10,817,907
Segment assets for all other businesses	329,207	324,638
Items excluded from segment assets:		
Cash and other investments (I)	64,436	14,996
Recoverable income taxes	11,504	27,907
Deferred tax assets	616,105	482,836
Bond issuance costs	50,884	53,474
Total Consolidated Assets	$12,163,048	$11,721,758

(I) Excludes amounts specifically related to the gas segment.

NOTE 16—GUARANTOR SUBSIDIARIES FINANCIAL INFORMATION:

The payment obligations under the $1,500,000, 8.000% per annum notes due April 1, 2017, the $1,250,000, 8.250% per annum notes due April 1, 2020, and the $250,000, 6.375% per annum notes due March 1, 2021 issued by CONSOL Energy are jointly and severally, and also fully and unconditionally guaranteed by substantially all subsidiaries of CONSOL Energy. In accordance with positions established by the Securities and Exchange Commission (SEC), the following financial information sets forth separate financial information with respect to the parent, CNX Gas, a guarantor subsidiary, the remaining guarantor subsidiaries and the non-guarantor subsidiaries. The principal elimination entries include investments in subsidiaries and certain intercompany balances and transactions. CONSOL Energy, the parent, and a guarantor subsidiary manage several assets and liabilities of all other wholly owned subsidiaries. These include, for example, deferred tax assets, cash and other post-employment liabilities. These assets and liabilities are reflected as parent company or guarantor company amounts for purposes of this presentation.

Income Statement for the three months ended September 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$199,100	$1,163,339	$60,873	$(1,623)	$1,421,689
Sales—Purchased Gas	—	1,155	—	—	—	1,155
Sales—Gas Royalty Interests	—	17,083	—	—	—	17,083
Freight—Outside	—	—	59,871	—	—	59,871
Other Income (including equity earnings)	232,472	(13,788)	33,414	1,412	(231,579)	21,931
Total Revenue and Other Income	232,472	203,550	1,256,624	62,285	(233,202)	1,521,729
Cost of Goods Sold and Other Operating Charges	23,375	91,376	682,055	58,401	24,061	879,268
Purchased Gas Costs	—	398	—	—	—	398
Transaction and Financing Fees	14,907	—	—	—	—	14,907
Gas Royalty Interests' Costs	—	15,420	—	—	(11)	15,409
Related Party Activity	2,653	—	(8,346)	478	5,215	—
Freight Expense	—	—	59,871	—	—	59,871
Selling, General and Administrative Expense	—	28,266	43,627	472	(25,673)	46,692
Depreciation, Depletion and Amortization	3,301	58,131	97,745	573	—	159,750
Abandonment of Long-Lived Assets	—	—	338	—	—	338
Interest Expense	58,421	2,332	(1,784)	13	(98)	58,884
Taxes Other Than Income	1,805	7,154	76,137	694	—	85,790
Total Costs	104,462	203,077	949,643	60,631	3,494	1,321,307
Earnings (Loss) Before Income Taxes	128,010	473	306,981	1,654	(236,696)	200,422
Income Tax Expense (Benefit)	(39,319)	(2,440)	74,226	626	—	33,093
Net Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$167,329	$2,913	$232,755	$1,028	$(236,696)	$167,329

Balance Sheet at September 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Assets:						
Current Assets:						
Cash and Cash Equivalents	$61,738	$408,723	$1,700	$362	$—	$472,523
Accounts and Notes Receivable:						
Trade	—	62,629	609	439,838	—	503,076
Securitized	—	—	—	—	—	—
Other	4,209	313,695	10,162	3,548	—	331,614
Inventories	—	6,481	193,071	42,139	—	241,691
Recoverable Income Taxes	(9,031)	40,451	(19,916)	—	—	11,504
Deferred Income Taxes	173,522	(16,275)	—	—	—	157,247
Prepaid Expenses	21,128	98,802	61,562	2,771	—	184,263
Total Current Assets	251,566	914,506	247,188	488,658	—	1,901,918
Property, Plant and Equipment:						
Property, Plant and Equipment	191,015	5,355,103	8,266,417	24,728	—	13,837,263
Less-Accumulated Depreciation, Depletion and Amortization	106,605	731,781	3,910,824	16,953	—	4,766,163
Property, Plant and Equipment-Net	84,410	4,623,322	4,355,593	7,775	—	9,071,100
Other Assets:						
Deferred Income Taxes	907,287	(448,429)	—	—	—	458,858
Investment in Affiliates	8,718,375	91,853	890,705	—	(9,525,115)	175,818
Restricted Cash	20,291	—	—	—	—	20,291
Other	136,489	353,794	34,487	10,293	—	535,063
Total Other Assets	9,782,442	(2,782)	925,192	10,293	(9,525,115)	1,190,030
Total Assets	$10,118,418	$5,535,046	$5,527,973	$506,726	$(9,525,115)	$12,163,048
Liabilities and Stockholders' Equity:						
Current Liabilities:						
Accounts Payable	$120,557	$184,771	$132,130	$11,209	$—	$448,667
Accounts Payable (Recoverable)—Related Parties	2,800,011	4,255	(3,164,631)	360,365	—	—
Current Portion Long-Term Debt	779	5,244	13,514	769	—	20,306
Other Accrued Liabilities	534,450	54,223	233,440	11,826	—	833,939
Total Current Liabilities	3,455,797	248,493	(2,785,547)	384,169	—	1,302,912
Long-Term Debt:	3,000,932	50,565	125,835	1,400	—	3,178,732
Deferred Credits and Other Liabilities						
Postretirement Benefits Other Than Pensions	—	—	3,094,164	—	—	3,094,164
Pneumoconiosis Benefits	—	—	177,162	—	—	177,162
Mine Closing	—	—	401,049	—	—	401,049
Gas Well Closing	—	63,094	55,431	—	—	118,525
Workers' Compensation	—	—	149,651	176	—	149,827
Salary Retirement	114,543	—	—	—	—	114,543

Reclamation	—	—	39,513	—	—	39,513
Other	120,403	22,984	16,487	4	—	159,878
Total Deferred Credits and Other Liabilities	234,946	86,078	3,933,457	180	—	4,254,661
Total CONSOL Energy Inc. Stockholders' Equity	3,426,743	5,149,910	4,254,228	120,977	(9,525,115)	3,426,743
Noncontrolling Interest	—	—	—	—	—	—
Total Liabilities and Stockholders' Equity	$10,118,418	$5,535,046	$5,527,973	$506,726	$(9,525,115)	$12,163,048

Income Statement for the three months ended September 30, 2010 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$204,454	$1,010,530	$47,981	$(2,466)	$1,260,499
Sales—Purchased Gas	—	3,524	—	—	—	3,524
Sales—Gas Royalty Interests	—	18,131	—	—	—	18,131
Freight—Outside	—	—	37,269	—	—	37,269
Other Income (including equity earnings)	121,067	1,642	18,548	8,455	(119,842)	29,870
Total Revenue and Other Income	121,067	227,751	1,066,347	56,436	(122,308)	1,349,293
Cost of Goods Sold and Other Operating Charges	25,292	76,093	685,015	47,339	17,080	850,819
Purchased Gas Costs	—	3,333	—	—	—	3,333
Transaction and Financing Fees	333	2	2	—	—	337
Gas Royalty Interests' Costs	—	16,424	—	—	(16)	16,408
Related Party Activity	(11,119)	—	(5,428)	490	16,057	—
Freight Expense	—	—	37,269	—	—	37,269
Selling, General and Administrative Expense	—	25,375	34,230	342	(21,225)	38,722
Depreciation, Depletion and Amortization	2,548	58,909	99,310	662	—	161,429
Interest Expense	61,789	2,154	2,574	6	(93)	66,430
Taxes Other Than Income	2,352	10,031	70,366	657	—	83,406
Total Costs	81,195	192,321	923,338	49,496	11,803	1,258,153
Earnings (Loss) Before Income Taxes	39,872	35,430	143,009	6,940	(134,111)	91,140
Income Tax Expense (Benefit)	(35,511)	14,097	34,545	2,626	—	15,757
Net Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$75,383	$21,333	$108,464	$4,314	$(134,111)	$75,383

Balance Sheet at December 31, 2010:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Assets:						
Current Assets:						
Cash and Cash Equivalents	$11,382	$16,559	$3,235	$1,618	$—	$32,794
Accounts and Notes Receivable:						
Trade	—	65,197	646	186,687	—	252,530
Securitized	200,000	—	—	—	—	200,000
Other	4,635	3,361	10,915	2,678	—	21,589
Inventories	—	4,456	203,962	50,120	—	258,538
Recoverable Income Taxes	(3,189)	35,717	—	—	—	32,528
Deferred Income Taxes	173,211	960	—	—	—	174,171
Prepaid Expenses	35,297	57,907	39,309	10,343	—	142,856
Total Current Assets	421,336	184,157	258,067	251,446	—	1,115,006
Property, Plant and Equipment:						
Property, Plant and Equipment	166,884	6,336,121	8,422,235	26,118	—	14,951,358
Less-Accumulated Depreciation, Depletion and Amortization	91,952	628,506	4,083,693	17,956	—	4,822,107
Property, Plant and Equipment-Net	74,932	5,707,615	4,338,542	8,162	—	10,129,251
Other Assets:						
Deferred Income Taxes	902,188	(417,342)	—	—	—	484,846
Investment in Affiliates	7,833,948	23,569	943,674	11,087	(8,718,769)	93,509
Restricted Cash	20,291	—	—	—	—	20,291
Other	118,149	37,268	61,532	10,758	—	227,707
Total Other Assets	8,874,576	(356,505)	1,005,206	21,845	(8,718,769)	826,353
Total Assets	$9,370,844	$5,535,267	$5,601,815	$281,453	$(8,718,769)	$12,070,610
Liabilities and Stockholders' Equity:						
Current Liabilities:						
Accounts Payable	$130,063	$101,944	$113,036	$8,968	$—	$354,011
Accounts Payable (Recoverable)-Related Parties	2,363,108	30,302	(2,543,991)	150,581	—	—
Short-Term Notes Payable	155,000	129,000	—	—	—	284,000
Current Portion of Long-Term Debt	758	9,851	13,589	585	—	24,783
Borrowings under Securitization Facility	200,000	—	—	—	—	200,000
Other Accrued Liabilities	302,788	59,960	425,735	13,508	—	801,991
Total Current Liabilities	3,151,717	331,057	(1,991,631)	173,642	—	1,664,785
Long-Term Debt:	3,000,702	58,905	125,627	904	—	3,186,138
Deferred Credits and Other Liabilities:						
Postretirement Benefits Other Than Pensions	—	—	3,077,390	—	—	3,077,390
Pneumoconiosis Benefits	—	—	173,616	—	—	173,616
Mine Closing	—	—	393,754	—	—	393,754

Gas Well Closing	—	60,027	70,951	—	—	130,978
Workers’ Compensation	—	—	148,265	49	—	148,314
Salary Retirement	161,173	—	—	—	—	161,173
Reclamation	—	—	53,839	—	—	53,839
Other	112,775	25,483	6,352	—	—	144,610
Total Deferred Credits and Other Liabilities	273,948	85,510	3,924,167	49	—	4,283,674
Total CONSOL Energy Inc. Stockholders’ Equity	2,944,477	5,068,259	3,543,652	106,858	(8,718,769)	2,944,477
Noncontrolling Interest	—	(8,464)	—	—	—	(8,464)
Total Liabilities and Stockholders’ Equity	$9,370,844	$5,535,267	$5,601,815	$281,453	$(8,718,769)	$12,070,610

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Income Statement for the nine months ended September 30, 2011 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$566,272	$3,559,954	$171,027	$(4,086)	$4,293,167
Sales—Purchased Gas	—	3,297	—	—	—	3,297
Sales—Gas Royalty Interests	—	52,191	—	—	—	52,191
Freight—Outside	—	—	156,311	—	—	156,311
Other Income (including equity earnings)	629,116	(9,473)	55,051	20,008	(624,634)	70,068
Total Revenue and Other Income	629,116	612,287	3,771,316	191,035	(628,720)	4,575,034
Cost of Goods Sold and Other Operating Charges	86,775	238,158	2,059,011	166,106	70,326	2,620,376
Purchased Gas Costs	—	2,850	—	—	—	2,850
Transaction and Financing Fees	14,907	—	—	—	—	14,907
Loss on Debt Extinguishment	16,090	—	—	—	—	16,090
Gas Royalty Interests' Costs	—	46,620	—	—	(38)	46,582
Related Party Activity	117	—	(21,083)	1,479	19,487	—
Freight Expense	—	—	156,122	—	—	156,122
Selling, General and Administrative Expense	—	82,053	121,562	1,072	(74,376)	130,311
Depreciation, Depletion and Amortization	8,665	159,109	297,017	1,821	—	466,612
Abandonment of Long-Lived Assets	—	—	115,817	—	—	115,817
Interest Expense	178,849	7,564	3,799	40	(289)	189,963
Taxes Other Than Income	5,191	23,230	234,411	2,289	—	265,121
Total Costs	310,594	559,584	2,966,656	172,807	15,110	4,024,751
Earnings (Loss) Before Income Taxes	318,522	52,703	804,660	18,228	(643,830)	550,283
Income Tax Expense (Benefit)	(118,340)	18,029	206,837	6,895	—	113,421
Net Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$436,862	$34,674	$597,823	$11,333	$(643,830)	$436,862

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Income Statement for the nine months ended September 30, 2010 (unaudited):

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Sales—Outside	$—	$570,591	$2,939,338	$145,151	$(4,951)	$3,650,129
Sales—Purchased Gas	—	8,280	—	—	—	8,280
Sales—Gas Royalty Interests	—	46,621	—	—	—	46,621
Freight—Outside	—	—	96,544	—	—	96,544
Other Income (including equity earnings)	399,464	3,066	41,033	22,704	(389,141)	77,126
Total Revenue and Other Income	399,464	628,558	3,076,915	167,855	(394,092)	3,878,700
Cost of Goods Sold and Other Operating Charges	68,014	184,209	1,998,686	138,730	46,813	2,436,452
Purchased Gas Costs	—	6,980	—	—	—	6,980
Transaction and Financing Fees	61,083	3,330	2	—	—	64,415
Gas Royalty Interests' Costs	—	40,182	—	—	(49)	40,133
Related Party Activity	(12,357)	—	(10,293)	1,458	21,192	—
Freight Expense	—	—	96,544	—	—	96,544
Selling, General and Administrative Expense	—	63,067	95,595	982	(51,747)	107,897
Depreciation, Depletion and Amortization	8,377	139,954	263,046	2,002	—	413,379
Interest Expense	125,787	6,177	7,909	16	(276)	139,613
Taxes Other Than Income	7,755	21,534	212,404	2,138	—	243,831
Total Costs	258,659	465,433	2,663,893	145,326	15,933	3,549,244
Earnings (Loss) Before Income Taxes	140,805	163,125	413,022	22,529	(410,025)	329,456
Income Tax Expense (Benefit)	(101,515)	62,672	105,611	8,523	—	75,291
Net Income (Loss)	$242,320	$100,453	$307,411	$14,006	$(410,025)	$254,165
Less: Net Income Attributable to Noncontrolling Interest	—	—	—	—	(11,845)	(11,845)
Net Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$242,320	$100,453	$307,411	$14,006	$(421,870)	$242,320

Cash Flow for the Nine Months Ended September 30, 2011 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used in) Operating Activities	$515,622	$313,221	$425,702	$(2,141)	$—	$1,252,404
Cash Flows from Investing Activities:						
Capital Expenditures	$(26,578)	$(535,068)	$(435,817)	$—	$—	$(997,463)
Distributions from Equity Affiliates	—	66,590	4,270	—	—	70,860
Other Investing Activities	10	688,505	5,304	1,472	—	695,291
Net Cash (Used in) Provided by Investing Activities	$(26,568)	$220,027	$(426,243)	$1,472	$—	$(231,312)
Cash Flows from Financing Activities:						
Dividends Paid	$(67,972)	$—	$—	$—	$—	$(67,972)
Payments on Short-Term Borrowings	(155,000)	(129,000)	—	—	—	(284,000)
Payments on Securitization Facility	(200,000)	—	—	—	—	(200,000)
Payments on Long-Term Notes, including redemption premium	(265,785)	—	—	—	—	(265,785)
Proceeds from Long-Term Notes	250,000	—	—	—	—	250,000
Debt Issuance and Financing Fees	(10,499)	(5,040)	—	—	—	(15,539)
Other Financing Activities	10,559	(7,044)	(994)	(588)	—	1,933
Net Cash (Used in) Provided by Financing Activities	$(438,697)	$(141,084)	$(994)	$(588)	$—	$(581,363)

Cash Flow for the Nine Months Ended September 30, 2010 (unaudited):

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	Non-Guarantors	Elimination	Consolidated
Net Cash (Used in) Provided by Operating Activities	$(3,373,370)	$267,894	$3,983,670	$736	$—	$878,930
Cash Flows from Investing Activities:						
Capital Expenditures	$—	$(292,495)	$(529,413)	$—	$—	$(821,908)
Distributions from Equity Affiliates	—	—	6,867	—	—	6,867
Acquisition of Dominion Exploration and Production Business	—	—	(3,474,199)	—	—	(3,474,199)
Purchase of CNX Gas Noncontrolling Interest	(991,034)	—	—	—	—	(991,034)
Other Investing Activities	—	48	24,896	—	—	24,944
Net Cash Used in Investing Activities	$(991,034)	$(292,447)	$(3,971,849)	$—	$—	$(5,255,330)
Cash Flows from Financing Activities:						
Dividends Paid	$(63,276)	$—	$—	$—	$—	$(63,276)
(Payments on) Proceeds from Short-Term Borrowings	(279,000)	20,050	—	—	—	(258,950)
Proceeds from Securitization Facility	150,000	—	—	—	—	150,000

Proceeds from Long-Term Notes	2,750,000	—	—	—	—	2,750,000
Proceeds from Issuance of Common Stock	1,828,862	—	—	—	—	1,828,862
Debt Issuance and Financing Fees	(92,998)	8,774	—	—	—	(84,224)
Other Financing Activities	12,051	4,524	(12,230)	(382)	—	3,963
Net Cash Provided by (Used in) Financing Activities	$4,305,639	$33,348	$(12,230)	$(382)	$—	$4,326,375

NOTE 17-RECENT ACCOUNTING PRONOUNCEMENTS:

In September 2011, the Financial Accounting Standards Board issued an update to the Compensation-Retirement Benefits-Multiemployer Plans Subtopic 715-80 of the Accounting Standards Codification which is intended to provide financial statement users with more information to assess the potential future cash flow implications relating to an employer's participation in multiemployer pension plans. The required additional disclosures will also indicate the financial health of all of the significant plans in which the employer participates and assist a financial statement user to access additional information that is available outside the financial statements. The effective date of this update is December 15, 2011 with early adoption permitted. We believe adoption of this new guidance will not have a material impact on CONSOL Energy's financial statements as this update has an impact on presentation only.

In June 2011, the Financial Accounting Standards Board issued an update to the Comprehensive Income Topic of the Accounting Standards Codification intended to improve the comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. This update eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity, requires consecutive presentation of the statement of net income and other comprehensive income, and requires an entity to present reclassification adjustments on the face of the financial statements from other comprehensive income (OCI) to net income. The effective date of this update is December 15, 2011 with early adoption permitted. We believe adoption of this new guidance will not have a material impact on CONSOL Energy's financial statements as these updates have an impact on presentation only.

NOTE 18—SUBSEQUENT EVENTS:

On October 21, 2011, CONSOL Energy, through its subsidiary, CNX Gas Company LLC, completed a sale to Hess Ohio Developments, LLC (Hess) of 50% of its nearly 200,000 Utica Shale acres in Ohio for consideration of approximately $594,000, of which $59,818 was paid at closing. Additionally, CONSOL Energy and Hess entered into a joint development agreement pursuant to which Hess agreed to pay approximately $534,000 in the form of a 50% drilling carry of certain CONSOL Energy working interest obligations as the acreage is developed. The estimated gain on the transaction is $52,737 and will be recognized in the Consolidated Statements of Income as Other Income during the three months ended December 31, 2011. CONSOL Energy and Hess anticipate commencing initial drilling operations in the three months ended December 31, 2011.

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ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

Third quarter demand for U.S. thermal and metallurgical coal continued at the strong pace set in the second quarter. Demand from domestic electric generators increased slightly over last year's record demand, but low natural gas prices have limited growth for coal producers. Continued international demand for U.S. coals, both thermal and metallurgical, has also been strong. Total U.S. coal exports are likely to exceed 100 million tons for 2011 - a level that has not been reached in nearly thirty years.

International demand for U.S. thermal coal was also strong in the third quarter as demonstrated by high market pricing. Prices for spot coal delivered into Europe had little volatility during the third quarter with prices trading within a $5.00 band. Trade to Europe has been limited to available port space along the U.S. east coast and has been increasingly turning to the U.S. Gulf coast as a departure point. Space at east coast terminals has been predominately claimed by higher value metallurgical coals, but port operators are optimizing capacities and rehabilitating facilities to take advantage of strong export markets. Demand growth has been spurred by traditional coal suppliers to Europe, Colombia and South Africa's entrance into new markets. Long-term exports to Europe are expected to remain strong as older nuclear units are retired and subsidized mining in Europe is phased-out.

Domestically, September coal inventories at electric generators were 19 to 22 million tons below last year's level. U.S. electric demand during the third quarter of 2011 was estimated to be comparable to 2010 levels - which were unusually high due to record cooling days across much of the country. Similarly, coal inventories at electric utilities in CONSOL Energy's traditional markets are at the lowest levels in six years as consecutive high cooling load summers, coupled with record deliveries to export facilities, have reduced stockpiles at generators.

CONSOL Energy's thermal coal continues to be sold out for 2011. During the three months ended September 30, 2011, CONSOL Energy priced 17 million tons of thermal coal for 2012 at an average price of $64.10, which raised our average realized price for 2012 to $62.37 per ton. CONSOL Energy is already approximately 84% sold out of this category for 2012. If tightening regulations are deferred allowing older coal fired plants to continue running, generators may be in need of additional coal supplies. Current customer inventories in our sales area are very low. Export thermal demand continues to grow with an additional 250 thousand tons sold in the three months ended September 30, 2011 for 2012 deliveries to European utility customers at prices higher than domestic thermal sales and nearly equal to our high volatile metallurgical coal sales. The Company expects total export thermal sales for 2011 to be 2.3 million tons.

Metallurgical coal demand continued the strong pace set earlier this year as world blast furnace output increased 6.4% during the first nine months of 2011 compared to the same period of 2010. China continues to provide the bulk of world iron production with almost 59% of world production and a 8.5% year-to-date increase compared to the same period in 2010. Although European steelmakers have shown signs of a slowdown, global production remains strong in Asia. In particular, Japanese industry has been increasing production, indicating a recovery from this year's earthquake and tsunami.

Supply of metallurgical coal continues to remain tight due to the continued rapid increase in demand as well as lingering problems associated with bringing Australian mines back into full production after spring flooding. The strong global demand for steel combined with tight supply has created a very strong market for metallurgical coal. CONSOL Energy is well positioned to take advantage of this market with its low cost Buchanan low-vol operation, low cost Northern Appalachia high-vol operations and mid-vol operations set to open in early 2012.

High demand continues for CONSOL Energy's Buchanan Mine low volatile metallurgical coal and supply remains constrained by global weather and labor issues. In 2012, excluding legacy contracts for 221 thousand tons, CONSOL Energy has already sold 0.9 million tons of Buchanan coal priced at $213 per short ton, FOB mine. High volatile metallurgical coal continues to benefit from increased market penetration into Asia as well as sales into new markets for testing purposes. As a result of a prior test, CONSOL Energy has signed a new sales order with a U.S. customer for 700 thousand tons in 2012, at prices within expectations. Two additional tests with European steel makers continues. Demand for CONSOL Energy's high volatile metallurgical coal will continue to be dependent on our ability to increase market penetration. CONSOL Energy has 3.7 million tons unpriced for 2012.

COAL DIVISION GUIDANCE
(Tons in millions)

	4Q 2011	2011	2012	2013
Estimated Coal Sales	14.7-15.3	62.0-62.6	59.5-61.5	60.5-62.5
Estimated Low-Vol Met Sales	1.0-1.2	5.3-5.5	4.5-5.0	4.5-5.0
Tonnage - Firm	0.7	5.0	1.1	0.2
Tonnage - Open	0.3-0.5	0.3-0.5	3.4-3.9	4.3-4.8
Average Price - Sold (firm)	$199.72	$192.92	$185.48	$91.74
Price - Estimated (for open tonnage)	$210-$220	$210-$220	$180-$190	N/A
Estimated High-Vol Met Sales	1.5	5.1	5.0	5.0
Tonnage - Firm	1.2	4.8	1.2	0.2
Tonnage - Open	0.3	0.3	3.8	4.8
Average Price - Sold (firm)	$75.01	$79.40	$81.96	$90.20
Price - Estimated (for open tonnage)	$74-$80	$74-$80	$70-$75	N/A
Estimated Thermal Sales	approx. 12.4	approx. 52.0	approx. 50.5	approx. 51.0
Tonnage - Firm	12.4	52.0	41.9	21.3
Tonnage - Open	—	—	N/A	N/A
Average Price - Sold (firm)	$58.47	$58.77	$62.37	$61.87
Price - Estimated (for open tonnage)	N/A	N/A	N/A	N/A

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

Natural gas markets enjoyed record third quarter demand as the second consecutive year of very high cooling degree days caused record demand for gas from electric generators. Supply however, has continued to grow at strong rates due to the prolific nature of new shale resources. This supply / demand imbalance is being brought back into balance in the short term by decreased imports from liquefied natural gas (LNG) and Western Canadian pipeline imports as well as increased exports to Eastern Canada and Mexico. CONSOL Energy believes longer-term rebalancing will be aided by declining conventional production and the shift in drilling towards oil and “liquids rich” gas plays.

Longer-term prospects for natural gas markets remain appealing as the U.S. continues to build more high-efficiency gas electric power plants and gas consumption increases in 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 enhance the value of its portfolio of long-lived energy resources.

CONSOL Energy expects its net gas production to be between 150-152 Bcf for the year ended December 31, 2011. Gas production for the three months ended December 31, 2011 is expected to be approximately 36-38 Bcf, net to CONSOL Energy.

A return to normal weather patterns could have a negative short-term impact on CONSOL Energy's natural gas and domestic thermal coal demand. Additionally, there is uncertainty in the short-term economic outlook driven by the European sovereign debt crisis, high U.S. unemployment rates and instability in the Middle East oil-producing region. This uncertainty makes a slowing of global economic expansion more possible. However, the fundamental long-term drivers of CONSOL Energy's business remain unchanged as 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 nine months ended September 30, 2011 and the related subsequent event period. 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, CONSOL Energy, through its subsidiary, CNX Gas Company LLC, completed a sale to Hess Ohio Developments, LLC (Hess) of 50% of its nearly 200,000 Utica Shale acres in Ohio for consideration of approximately $594 million, of which $60 million was paid at closing. 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. CONSOL Energy and Hess anticipate commencing initial drilling operations in the fourth quarter of 2011.

- On September 30, 2011, CNX Gas Company LLC (CNX Gas) 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 628,000 acres and 50% of the Company's undivided interest in certain of its existing Marcellus Shale wells and related leases. On September 30, 2011, cash proceeds of $519 million were received from Noble. In addition to the cash proceeds, a one year note receivable due on September 30, 2012 in the amount of $312 million and a two year note receivable due on September 30, 2013 in the amount of $296 million have been recorded. As part of the transaction, CONSOL Energy 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.

- On September 30 2011, CNX Gas 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. CONSOL Energy contributed its existing Marcellus Shale gathering infrastructure which had a net book value of $133 million and Noble contributed cash of approximately $73 million. On September 30, 2011, CONE made a cash distribution to CONSOL Energy in the amount of $73 million.

- 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 115,647 net acres of Marcellus Shale located in nine counties in southwestern Pennsylvania and north central West Virginia, in exchange for $193 million. The transaction became effective as of July 1, 2011.

- CONSOL Energy incurred costs of approximately $15 million in the three months ended September 30, 2011 related to the solicitation of consents from the holders of CONSOL'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 of the indentures for each of those notes, clarifying that the transactions contemplated by the August 2011 Asset Acquisition Agreements with Noble Energy and Hess Energy 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, 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 experience will receive a $1.00 per hour contribution (increasing to $1.50 per hour in 2014-2016) to the CDSP beginning January 1, 2012. All current UMWA represented employees will be given the opportunity to opt-out of future participation in the 1974 Pension Plan and instead participate in 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, contribution to various UMWA benefit funds, eligibility for various vacation days and sick days.

The total incremental cost of the revised terms of the contract over 2010 operating costs at CONSOL Energy's represented operations is projected to average approximately 3.5% per ton, per year over the term of the contract. CONSOL Energy expects a similar increase to impact all of CONSOL Energy's tons due to cost inflation that typically occurs at CONSOL Energy's non-represented mines.

- On October 24, 2011, certain subsidiaries of CONSOL Energy received notice from the trustees of the UMWA 1974 Pension Plan ("the Plan") stating that the Plan is considered to be in “seriously endangered” status for the plan year beginning July 1, 2011. The status of the plan is due to the funded percentage and projected funding deficiency. As a result, the Pension Protection Act requires the Plan 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 Plan from employers in the future. Because CONSOL Energy's subsidiaries are parties to the NBCWA which establishes their contribution obligations through December 31, 2016, such subsidiaries' contributions to the Plan will not increase as a consequence of any funding improvement plan adopted by the Plan to address the Plan's seriously endangered status.

- 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 $115 million charge to pre-tax earnings in June 2011. See Note 8—Property, Plant and Equipment in the Notes to the Consolidated Financial Statements of this Form 10-Q 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 of 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 affect this redemption, the Company effectively extended the maturity of the $250 million of long-term indebtedness 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 and synthetic rubber that we use in our operations and (ii) continued 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; in 2011 we plan to complete construction of pipelines to convey mine water from our Shoemaker Mine and the closed Windsor Mine to approved mixing zones in the Ohio River.

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. 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. 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 fracing 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

Three Months Ended September 30, 2011 Compared with Three Months Ended September 30, 2010

Net Income Attributable to CONSOL Energy Shareholders

CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $167 million, or $0.73 per diluted share, for the three months ended September 30, 2011. Net income attributable to CONSOL Energy shareholders was $75 million, or $0.33 per diluted share, for the three months ended September 30, 2010.

The coal division includes steam coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $268 million of earnings before income tax for the three months ended September 30, 2011 compared to $118 million for the three months ended September 30, 2010. The coal division sold 14.8 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, for the three months ended September 30, 2011 compared to 15.4 million tons for the three months ended September 30, 2010.

The average sales price and average costs per ton for all active coal operations were as follows:

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Average Sales Price per ton sold	$76.60	$63.71	$12.89	20.2 %
Average Costs per ton sold	55.91	49.98	5.93	11.9 %
Margin	$20.69	$13.73	$6.96	50.7 %

The higher average sales price per ton sold reflects continued gains that were achieved mainly by another strong quarter of our premium low volatile metallurgical coal, sustained demand for our high volatile metallurgical coal, and the continued benefit from higher negotiated prices for steam coal. Also, 2.5 million tons were sold on the export market at an average sales price of $139.58 per ton for the three months ended September 30, 2011 compared to 1.9 million tons at an average price of $110.83 per ton for the three months ended September 30, 2010.

Average costs per ton sold have increased in the period-to-period comparison due primarily to increased labor and labor related charges as a result of additional employees, increased overtime hours worked and the impact of the $1.50 per hour worked UMWA contract wage increases, $1.00 per hour worked related to the new UMWA contract and $0.50 per hour worked related to the prior UMWA contract, higher operating supplies and maintenance costs due to additional maintenance and equipment overhaul costs, additional roof control costs and higher costs associated with the sales price of coal sold, such as royalties and production related taxes. Also, depreciation, depletion and amortization costs increased due to additional assets placed in service after the 2010 period and increased expenses related to other post employment benefits (OPEB) and pension benefits. OPEB and pension expense increased due to employees retiring sooner than originally anticipated and average claim costs being higher than originally anticipated.

The total gas division includes coalbed methane (CBM), conventional, Marcellus and other gas. The total gas division did not significantly impact earnings before income tax for the three months ended September 30, 2011 when compared to $35 million for the three months ended September 30, 2010. Total gas production was 40.4 billion cubic feet for the three months ended September 30, 2011 compared to 35.8 billion cubic feet for the three months ended September 30, 2010.

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

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$4.92	$5.72	$(0.80)	(14.0)%
Average Costs per thousand cubic feet sold	3.93	4.08	(0.15)	(3.7)%
Margin	$0.99	$1.64	$(0.65)	(39.6)%

Total gas division outside sales revenue was $199 million for the three months ended September 30, 2011 compared to $205 million for the three months ended September 30, 2010. The decrease was primarily due to the 14.0% reduction in average sales price, offset, in part, by the 12.8% increase in volumes sold. The decrease in average sales price is the result of various gas swap transactions maturing 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 23.9 billion cubic feet of our produced gas sales volumes for the three months ended September 30, 2011 at an average price of $5.12 per thousand cubic feet. These financial hedges represented 13.6 billion cubic feet of our produced gas sales volumes for the three months ended September 30, 2010 at an average price of $7.39 per thousand cubic feet.

Total gas division costs decreased for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 primarily due to lower depreciation, depletion and amortization and lower gathering and compression costs partially offset by higher lifting costs. Lower depreciation, depletion and amortization rates were the result of the higher gas reserves at December 31, 2010 reducing unit rates. Lower gathering and compression costs were the result of the increase in volumes sold as actual dollars remained consistent in the period-to-period comparison. Lifting costs increased in the period-to-period comparison due to increased road maintenance and increased well service costs.

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. A detailed analysis of these total Company expenses are as follows:

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 Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Employee wages and related expenses	$21	$19	$2	10.5 %
Advertising and promotion	3	1	2	200.0 %
Contributions	3	1	2	200.0 %
Consulting and professional services	7	6	1	16.7 %
Miscellaneous	13	12	1	8.3 %
Total Company Selling, General and Administrative Expenses	$47	$39	$8	20.5 %

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

- Employee wages and related expenses increased $2 million which was primarily attributable to additional hiring of support staff in the period-to-period comparison.

- Advertising and promotion expense increased $2 million in the period-to-period comparison due to additional campaigns initiated in the 2011 period.

- Contributions expense increased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Consulting and professional services increased $1 million due to various corporate projects that occurred throughout both periods, none of which were individually material.
- Miscellaneous selling, general and administrative expenses increased $1 million primarily due to various corporate projects 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 $83 million for the three months ended September 30, 2011 compared to $70 million for the three months ended September 30, 2010. The increase of $13 million for total CONSOL Energy expense was due primarily to OPEB and salary pension expense. The higher OPEB and salary pension expense related to employees retiring sooner than originally anticipated and average claim costs being higher than previously anticipated. Also, higher long-term liability expenses in the period-to-period comparison were due to changes in the discount rates used at the measurement date, which is December 31. See Note 3—Components of Pension and Other Postretirement Benefit Plans Net Periodic Benefit Costs and Note 4—Components of Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation Net Periodic Benefit Costs in the Notes to the Unaudited Consolidated Financial Statements for additional detail of total Company expense increases.

TOTAL COAL SEGMENT ANALYSIS for the three months ended September 30, 2011 compared to the three months ended September 30, 2010:

The coal segment contributed $268 million of earnings before income tax for the three months ended September 30, 2011 compared to $118 million for the three months ended September 30, 2010. Variances by the individual coal segments are discussed below.

	For the Three Months Ended September 30, 2011					Difference to Three Months Ended September 30, 2010				
	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$732	$82	$308	$9	$1,131	$(9)	$60	$93	$6	$150
Purchased Coal	—	—	—	5	5	—	—	—	3	3
Total Outside Sales	732	82	308	14	1,136	(9)	60	93	9	153
Freight Revenue	—	—	—	60	60	—	—	—	22	22
Other Income	2	3	—	24	29	1	—	—	8	9
Total Revenue and Other Income	734	85	308	98	1,225	(8)	60	93	39	184
Costs and Expenses:										
Total operating costs	478	43	81	47	649	(40)	33	20	12	25
Total provisions	54	6	9	11	80	3	5	2	(27)	(17)
Total administrative & other costs	43	5	8	17	73	8	4	3	(7)	8
Depreciation, depletion and amortization	75	7	9	4	95	5	5	3	(17)	(4)
Total Costs and Expenses	650	61	107	79	897	(24)	47	28	(39)	12
Freight Expense	—	—	—	60	60	—	—	—	22	22
Total Costs	650	61	107	139	957	(24)	47	28	(17)	34
Earnings (Loss) Before Income Taxes	$84	$24	$201	$(41)	$268	$16	$13	$65	$56	$150

STEAM COAL SEGMENT

The steam coal segment contributed $84 million to total Company earnings before income tax for the three months ended September 30, 2011 compared to $68 million for the three months ended September 30, 2010. The steam coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced Steam Tons Sold (in millions)	12.2	13.7	(1.5)	(10.9)%
Average Sales Price Per Steam Ton Sold	$60.18	$54.02	$6.16	11.4 %
Average Operating Costs Per Steam Ton Sold	$39.21	$37.82	$1.39	3.7 %
Average Provision Costs Per Steam Ton Sold	$4.49	$3.74	$0.75	20.1 %
Average Selling, Administrative and Other Costs Per Steam Ton Sold	$3.52	$2.51	$1.01	40.2 %
Average Depreciation, Depletion and Amortization Costs Per Steam Ton Sold	$6.21	$5.07	$1.14	22.5 %
Total Average Costs Per Steam Ton Sold	$53.43	$49.14	$4.29	8.7 %
Margin Per Steam Ton Sold	$6.75	$4.88	$1.87	38.3 %

Steam coal revenue was $732 million for the three months ended September 30, 2011 compared to $741 million for the three months ended September 30, 2010. The $9 million decrease was attributable to the 1.5 million ton reduction in steam tons sold partially offset by the $6.16 per ton higher average sales price. The sales ton decrease was primarily due to a roof fall at the McElroy Mine and the 0.7 million tons of steam coal sold on the high volatile metallurgical coal market for the three months ended September 30, 2011 compared to the three months ended September 30, 2010. The higher average steam coal sales price in the 2011 period was the result of successful re-negotiation of several domestic steam contracts whose pricing took effect on January 1, 2011. Produced steam coal inventory was 1.6 million tons at September 30, 2011 compared to 2.1 million tons at September 30, 2010.

Other income attributable to the steam coal segment represents earnings from our equity affiliates that operate steam 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 steam coal segment were $478 million in the three months ended September 30, 2011 compared to $518 million in the three months ended September 30, 2010. Operating costs related to the steam coal segment have decreased primarily due to the additional steam coal sold on the high volatile metallurgical coal market.

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

- Average operating costs per steam ton sold increased due to fewer tons sold. Fixed costs are allocated over less tons, resulting in higher unit costs.
- Labor and related benefits average costs per ton sold were impaired, although total dollars expensed for these items were improved slightly. Average costs per ton sold were impacted by the 1.5 million ton reduction in sales tons. Labor benefit costs were impacted by 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 that the federal contributions are not sufficient to cover the benefits. This improvement was offset by higher contributions made to the 1974 Pension Trust (the Trust), which is a multi-employer pension plan. Contributions to the Trust were

negotiated under the National Bituminous Coal Wage Agreement. Contributions are based on a rate per hour worked by members of the United Mine Workers of America (UMWA). The contribution rate has increased $0.50 per hour worked in the 2011 period compared to the 2010 period. Reductions were also offset, in part, by 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 new collective bargaining agreement, in the period-to-period comparison.

- Average operating supplies & maintenance cost per ton sold increased due to higher fuel costs, additional roof control costs, additional maintenance and equipment overhaul costs. 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. Roof control costs also increased due to higher steel prices in the period-to-period comparison. Additional maintenance and equipment overhaul costs were related to additional equipment being serviced in the current period.
- Production taxes average cost per ton sold increased due to the $6.16 per ton higher average sales price.
- Subsidence costs per ton sold increased due to more structures and higher costs related to these structures that were impacted by longwall mining in the period-to-period comparison. Subsidence costs have also increased due to an increase in the length of streams that were impacted by longwall mining in the period-to-period comparison.
- These increases in average operating costs per ton for steam coal were offset, in part, by lower contract mining fees. Fewer contractors were retained to mine our reserves in the period-to-period comparison without a corresponding reduction in total steam coal sold which has resulted in lower average unit costs per ton sold.

Provision costs are comprised 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. The average provision costs attributable to the steam coal segment were $54 million for the three months ended September 30, 2011 compared to $51 million for the three months ended September 30, 2010. The increase in the steam coal provision expense was attributable to the total company increased long-term liability expense as discussed in the total Company results of operations section. The 1.5 million ton reduction in sales volumes also contributed to the higher average unit costs per ton sold.

Selling, administrative and other costs attributable to the steam 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 segment 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 steam coal segment were $43 million for the three months ended September 30, 2011 compared to $35 million for the three months ended September 30, 2010. The cost increases attributable to the steam 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 additional support staff in the period-to-period comparison. Higher average unit costs were also related to lower volumes of coal sold. Costs were allocated over less tons, resulting in higher unit costs.

Depreciation, depletion and amortization for the steam coal segment was $75 million for the three months ended September 30, 2011 compared to $70 million for the three months ended September 30, 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 steam 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 coupled with fewer tons sold resulted in a $1.14 increase in average depreciation, depletion and amortization costs per ton sold.

HIGH VOL METALLURGICAL COAL SEGMENT

The high volatile metallurgical coal segment contributed $24 million to total Company earnings before income tax for the three months ended September 30, 2011 compared to $11 million for the three months ended September 30, 2010. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Three Months Ended September 30,				
	2011	2010	Variance	Percent Change	
Produced High Vol Met Tons Sold (in millions)	1.0	0.3	0.7	233.3	%
Average Sales Price Per High Vol Met Ton Sold	$82.21	$65.38	$16.83	25.7	%
Average Operating Costs Per High Vol Met Ton Sold	$45.02	$30.02	$15.00	50.0	%
Average Provision Costs Per High Vol Met Ton Sold	$5.34	$2.75	$2.59	94.2	%
Average Selling, Administrative and Other Costs Per High Vol Met Ton Sold	$4.39	$1.94	$2.45	126.3	%
Average Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Sold	$7.22	$4.72	$2.50	53.0	%
Total Average Costs Per High Vol Met Ton Sold	$61.97	$39.43	$22.54	57.2	%
Margin Per High Vol Met Ton Sold	$20.24	$25.95	$(5.71)	(22.0	%)

High volatile metallurgical coal revenue was $82 million for the three months ended September 30, 2011 compared to $22 million for the three months ended September 30, 2010. Strength in the metallurgical coal market has continued to allow the export of Northern Appalachian coal, historically sold domestically on the steam coal market, to crossover to the Brazilian and Asian metallurgical coal markets. Average sales prices for high volatile metallurgical coal have increased due to growing the base of end user customers. CONSOL Energy sold 0.8 million tons of high volatile metallurgical coal in the export market at an average sales price of $80.65 per ton for the three months ended September 30, 2011 compared to 0.3 million tons at an average price of $65.38 for the three months ended September 30, 2010.

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 $43 million for the three months ended September 30, 2011 compared to $10 million for the three months ended September 30, 2010. Operating costs related to the high volatile metallurgical coal segment have 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 unit primarily changed due to the mix of mines shipping high volatile metallurgical coal. The increased cost structure of high volatile metallurgical coal is due to more Central Appalachian mines shipping high vol tons. Central Appalachian mines shipping high volatile metallurgical tons have higher cost structures than the Northern Appalachian mines included in the prior period.
- Labor and related benefits increased due to higher employee counts, higher non-union benefit rates and higher contributions per hour worked to the 1974 Pension Trust (Trust). Higher non-union benefit rates for active employees were related to the continued increase in healthcare costs. Higher contributions made to the Trust were discussed in the steam coal segment. 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 steam coal segment. Labor and related benefits also increased due to the impact of the wage increase 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 new collective bargaining agreement, in the period-to-period

comparison. Increased labor and related benefit costs per unit sold were offset, in part, by additional volumes of high volatile metallurgical tons sold in the period-to-period comparison.

- Average operating supplies & maintenance costs per ton sold increased due to additional maintenance and equipment overhaul costs and additional roof control costs. Additional maintenance and equipment overhaul costs were 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. Roof control costs also increased

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due to higher steel prices in the period-to-period comparison.

- Production taxes average cost per ton sold increased due to the $16.83 per ton higher average sales price.
- In-transit charges average cost per 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 Central Appalachian mines now shipping high volatile metallurgical coal.
- Subsidence costs per ton sold increased due to more structures and higher costs related to these structures that were impacted by longwall mining in the period-to-period comparison. Subsidence costs also increased due to an increase in the length of streams that were impacted by longwall mining in the period-to-period comparison.
- Average preparation plant costs per ton sold increased due to additional maintenance projects completed at our preparation plants in the period-to-period comparison.
- Average royalty costs per ton sold were lower in the period-to-period comparison due to fewer tons being mined from coal tracts that have a royalty, offset, in part, by higher average sales prices.

The provision expense attributable to the high volatile metallurgical coal segment was $6 million for the three months ended September 30, 2011 compared to $1 million for the three months ended September 30, 2010. The increase in the high volatile metallurgical coal provision expense was attributable to the total Company increase in 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 contributed to lower 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 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 segment 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 $5 million for the three months ended September 30, 2011 compared to $1 million for the three months ended September 30, 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 additional support staff in the period-to-period comparison. These increases in expense resulted in higher costs per ton sold and were offset, in part, by additional volumes of high volatile metallurgical coal sold.

Depreciation, depletion and amortization for the high volatile metallurgical coal segment was $7 million for the three months ended September 30, 2011 compared to $2 million for the three months ended September 30, 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 a higher unit rate 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 steam coal market.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $201 million to total Company earnings before income tax for the three months ended September 30, 2011 compared to $136 million for the three months ended September 30, 2010. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Three Months Ended September 30,				
	2011	2010	Variance	Percent Change	
Produced Low Vol Met Tons Sold (in millions)	1.5	1.3	0.2	15.4	%
Average Sales Price Per Low Vol Met Ton Sold	$207.21	$165.22	$41.99	25.4	%
Average Operating Costs Per Low Vol Met Ton Sold	$54.12	$47.99	$6.13	12.8	%
Average Provision Costs Per Low Vol Met Ton Sold	$6.69	$5.29	$1.40	26.5	%
Average Selling, Administrative and Other Costs Per Low Vol Met Ton Sold	$5.05	$3.61	$1.44	39.9	%
Average Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Sold	$6.28	$4.65	$1.63	35.1	%
Total Average Costs Per Low Vol Met Ton Sold	$72.14	$61.54	$10.60	17.2	%
Margin Per Low Vol Met Ton Sold	$135.07	$103.68	$31.39	30.3	%

Low volatile metallurgical coal revenue was $308 million for the three months ended September 30, 2011 compared to $215 million for the three months ended September 30, 2010. The $93 million increase was attributable to a $41.99 per ton higher average sales price due to the continued strengthening of the low volatile metallurgical coal market, both domestic and foreign. The continued strength of these markets is related to continued worldwide demand for premium low volatile metallurgical coal. CONSOL Energy sold 1.2 million tons of low volatile metallurgical coal in the export market at an average sales price of $214.74 per ton for the three months ended September 30, 2011 compared to 1.0 million tons at an average price of $165.01 per ton for the three months ended September 30, 2010. Produced low volatile metallurgical coal inventory was 0.1 million tons at September 30, 2011 and 2010.

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 $81 million for the three months ended September 30, 2011 compared to $61 million for the three months ended September 30, 2010. Operating costs related to the low volatile metallurgical coal segment increased primarily due to higher average operating costs per ton sold and higher volumes sold.

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

- Costs associated with the sales price of coal sold, such as royalties and production related taxes, increased due to the higher average sales prices received for low volatile metallurgical coal in the period-to-period comparison.
- Average preparation plant costs per ton sold increased due to additional maintenance projects completed and increased fuel costs at our preparation plant in the period-to-period comparison.
- Labor and related benefits increased in the period-to-period comparison due to additional employees, increased hours worked and increased non-union benefit rates for active employees which were related to the continued increase in healthcare costs.

The provision expense attributable to the low volatile metallurgical coal segment was $9 million for the three months ended September 30, 2011 compared to $7 million for the three months ended September 30, 2010. The increase in the low 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, low volatile metallurgical coal accretion expense related to mine closing and related liabilities remained consistent in the period-to-period comparison which contributed to lower 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 expenses, 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 segment 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 $8 million for the three months ended September 30, 2011 compared to $5 million for the three months ended September 30, 2010. The cost increase attributable to the low 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. 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 the 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 earlier in 2011.

Depreciation, depletion and amortization for the low volatile metallurgical coal segment was $9 million for the three months ended September 30, 2011 compared to $6 million for the three months ended September 30, 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. The increases in unit costs per ton sold were offset, in part, by additional 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 $41 million for the three months ended September 30, 2011 compared to a loss before income tax of $97 million for the three months ended September 30, 2010. The other coal segment includes purchased coal activities, idle mine activities, as well as various activities assigned to the coal division but not allocated to each individual mine.

Other coal segment produced coal sales include revenue from the sale of 0.1 million tons of coal which was recovered during the reclamation process at idled facilities for the three months ended September 30, 2011. Tons sold were insignificant in the three months ended September 30, 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 $5 million for the three months ended September 30, 2011 compared to $2 million for the three months ended September 30, 2010. The increase was primarily due to purchasing additional tons to supply a coal sales agreement.

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 offset in freight expense. Freight revenue was $60 million for the three months ended September 30, 2011 compared to $38 million for the three months ended September 30, 2010. The increase in freight revenue was primarily due to the 0.6 million ton increase in export tons in the period-to-period comparison.

Miscellaneous other income was $24 million for the three months ended September 30, 2011 compared to $16 million for the three months ended September 30, 2010. The increase of $8 million was primarily related to issuing pipeline right-of-ways to a third party which generated a gain of $10 million. This improvement was partially offset by various transactions that occurred throughout both periods, none of which were individually material.

Other coal segment total costs were $139 million for the three months ended September 30, 2011 compared to $156 million for the three months ended September 30, 2010. The decrease of $17 million was due to the following items:

	For the Three Months Ended September 30,		
	2011	2010	Variance
Closed and idle mine cost	$23	$71	$(48)
Litigation expense	2	3	(1)
Freight expense	60	38	22
Purchased coal	11	2	9
Other	43	42	1
Total other coal segment costs	$139	$156	$(17)

- Closed and idle mine costs decreased approximately $48 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010. The decrease was the result of a $29 million increase in the Fola reclamation liability in the 2010 period as a result of market conditions, permitting issues, new regulatory requirements and resulting changes in mining plans. Also, closed and idle mine costs decreased $14 million as the result of the change in mine plan at Mine 84 in the 2010 period. Due to the mine plan change, a portion of the previously developed area of the mine was abandoned. Closed and idle mine costs decreased $5 million due to other changes in the operational status of various other mines, between idled and operating, throughout both periods, none of which were individually material.
- Litigation expense decreased $1 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 related to various legal settlements, none of which were individually material.
- Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used for 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 offset in freight revenue. Freight expense increased $22 million primarily due to the 0.6 million ton increase in export tons in the period-to-period comparison.
- Purchased coal costs increased approximately $9 million in the period-to-period comparison primarily due to the increased volumes of coal purchased to supply various coal sales contracts.
- Other expenses related to the coal segment increased $1 million in the period-to-period comparison due to various miscellaneous transactions, none of which were individually material.

TOTAL GAS SEGMENT ANALYSIS for the three months ended September 30, 2011 compared to the three months ended September 30, 2010:
The gas segment did not significantly contribute to earnings before income tax for the three months ended September 30, 2011 compared to income of $35 million for the three months ended September 30, 2010.

	For the Three Months Ended September 30, 2011					Difference to Three Months Ended September 30, 2010				
	CBM	Conven-tional	Marcellus	Other Gas	Total Gas	CBM	Conven-tional	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$116	$39	$39	$3	$197	$(24)	$(6)	$23	$2	$(5)
Related Party	2	—	—	—	2	(1)	—	—	—	(1)
Total Outside Sales	118	39	39	3	199	(25)	(6)	23	2	(6)
Gas Royalty Interest	—	—	—	17	17	—	—	—	(2)	(2)
Purchased Gas	—	—	—	1	1	—	—	—	(2)	(2)
Other Income	—	—	—	(14)	(14)	—	—	—	(16)	(16)
Total Revenue and Other Income	118	39	39	7	203	(25)	(6)	23	(18)	(26)
Lifting	13	17	6	1	37	(1)	4	5	—	8
Gathering	25	8	3	—	36	1	3	(1)	(1)	2
General & Administration	15	8	4	1	28	(2)	1	1	4	4
Depreciation, Depletion and Amortization	26	15	15	2	58	(3)	(8)	10	(1)	(2)
Gas Royalty Interest	—	—	—	16	16	—	—	—	(1)	(1)
Purchased Gas	—	—	—	—	—	—	—	—	(3)	(3)
Exploration and Other Costs	—	—	—	6	6	—	—	—	(6)	(6)
Other Corporate Expenses	—	—	—	20	20	—	—	—	7	7
Interest Expense	—	—	—	2	2	—	—	—	—	—
Total Cost	79	48	28	48	203	(5)	—	15	(1)	9
Earnings Before Noncontrolling Interest and Income Tax	39	(9)	11	(41)	—	(20)	(6)	8	(17)	(35)
Noncontrolling Interest	—	—	—	—	—	—	—	—	—	—
Earnings Before Income Tax	$39	$(9)	$11	$(41)	$—	$(20)	$(6)	$8	$(17)	$(35)

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COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $39 million to the total Company earnings before income tax for the three months ended September 30, 2011 compared to $59 million for the three months ended September 30, 2010.

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced gas CBM sales volumes (in billion cubic feet)	23.3	23.0	0.3	1.3 %
Average CBM sales price per thousand cubic feet sold	$5.04	$6.16	$(1.12)	(18.2)%
Average CBM lifting costs per thousand cubic feet sold	$0.54	$0.59	$(0.05)	(8.5)%
Average CBM gathering costs per thousand cubic feet sold	$1.06	$1.06	$—	— %
Average CBM general & 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	$1.23	$(0.13)	(10.6)%
Total Average CBM costs per thousand cubic feet sold	$3.36	$3.58	$(0.22)	(6.1)%
Average Margin for CBM	$1.68	$2.58	$(0.90)	(34.9)%

CBM sales revenues were $118 million for the three months ended September 30, 2011 compared to $143 million for the three months ended September 30, 2010. The $25 million decrease was primarily due to a 18.2% decrease in average sales price per thousand cubic feet sold, offset, in part, by a 1.3% increase in average volumes sold. The decrease in CBM average sales price is the result of various gas swap transactions maturing in each period. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 16.6 billion cubic feet of our produced CBM gas sales volumes for the three months ended September 30, 2011 at an average price of $5.27 per thousand cubic feet. In the three months ended September 30, 2010, these financial hedges represented 13.1 billion cubic feet at an average price of $7.47 per thousand cubic feet. CBM sales volumes increased 0.3 billion cubic feet primarily due to additional wells coming on-line from our on-going drilling program.

Total costs for the CBM segment were $79 million for the three months ended September 30, 2011 compared to $84 million for the three months ended September 30, 2010. Lower costs in the period-to-period comparison were primarily related to lower unit costs offset, in part, by increased volumes sold.

CBM lifting costs were $13 million in the three months ended September 30, 2011 compared to $14 million in the three months ended September 30, 2010. Lower average CBM lifting unit costs were related to reduced idle rig costs due to a contract buyout and reduced contract services primarily due to lower electrical contract labor. These improvements were partially offset by increased road and equipment maintenance costs.

CBM gathering costs were $25 million for the three months ended September 30, 2011 compared to $24 million for the three months ended September 30, 2010. The $1 million increase was due to various activities that occurred throughout both periods, none of which were individually material.

General and administrative costs attributable to the total gas division were $28 million for the three months ended September 30, 2011 compared to $24 million for the three months ended September 30, 2010. The $4 million increase was attributable to additional corporate service charges from CONSOL Energy and additional staffing. The 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 was primarily due to additional support staffing requirements.

General and administrative costs for the CBM segment were $15 million for the three months ended September 30, 2011 compared to $17 million for the three months ended September 30, 2010. General and administrative costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. Unit costs were reduced in the period-to-period comparison primarily due to CBM being a lower percentage of total gas volumes primarily due to increased Marcellus volumes.

Depreciation, depletion and amortization attributable to the CBM segment was $26 million for the three months ended September 30, 2011 compared to $29 million for the three months ended September 30, 2010. There was approximately $18 million, or $0.77 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 for the three months ended September 30, 2011. The production portion of depreciation, depletion and amortization was $22 million, or $0.95 per unit-of-production for the three months ended September 30, 2010. The CBM unit-of-production rate decreased due to revised rates which are generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. There was approximately $8 million, or $0.33 average per unit cost of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight line basis in the three months ended September 30, 2011. The non-production related depreciation, depletion and amortization was $7 million, or $0.28 per thousand cubic feet for the three months ended September 30, 2010. The increase was related to additional gathering assets placed in service after the 2010 period.

CONVENTIONAL GAS SEGMENT

The conventional segment had a loss before income tax of $9 million in the three months ended September 30, 2011 compared to a loss before income tax of $3 million in the three months ended September 30, 2010.

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced gas Conventional sales volumes (in billion cubic feet)	7.8	9.1	(1.3)	(14.3)%
Average Conventional sales price per thousand cubic feet sold	$4.98	$5.00	$(0.02)	(0.4)%
Average Conventional lifting costs per thousand cubic feet sold	$2.19	$1.37	$0.82	59.9%
Average Conventional gathering costs per thousand cubic feet sold	$1.00	$0.60	$0.40	66.7%
Average Conventional general & administrative costs per thousand cubic feet sold	$0.93	$0.80	$0.13	16.3%
Average Conventional depreciation, depletion and amortization costs per thousand cubic feet sold	$1.96	$2.49	$(0.53)	(21.3)%
Total Average Conventional costs per thousand cubic feet sold	$6.08	$5.26	$0.82	15.6%
Average Margin for Conventional	$(1.10)	$(0.26)	$(0.84)	323.1%

Conventional sales revenues were $39 million for the three months ended September 30, 2011 compared to $45 million for the three months ended September 30, 2010. The $6 million decrease was primarily due to the 14.3% decrease in volumes sold. Conventional sales volumes decreased 1.3 billion cubic feet for the three months ended September 30, 2011 compared to the 2010 period primarily due to normal well declines without a corresponding increase in wells drilled, as the focus of the gas division is to develop the Marcellus acreage. Average sales price decreased primarily due to lower general market prices of natural gas and oil in the period-to-period comparison. This decrease was partially offset by the result of various gas swap transactions that matured in the three months ended September 30, 2011. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 3.9 billion cubic feet of our produced conventional gas sales volumes for the three months ended September 30, 2011 at an average price of $4.94 per thousand cubic feet. There were no conventional gas swap transactions that occurred in the three months ended September 30, 2010.

Total costs for the conventional segment were $48 million for both the three months ended September 30, 2011 and 2010. When combined with the decrease in volumes sold, this resulted in an increase in total average conventional costs per thousand cubic feet sold.

Conventional lifting costs were $17 million for the three months ended September 30, 2011 compared to $13 million for the three months ended September 30, 2010. Lifting costs per unit increased due to increased road maintenance costs, increased well tending charges, as a result of additional wells turned in line, increased slip repairs on various well pads, increased non-operated well costs and increased in swabbing charges to mitigate production issues.

Conventional gathering costs were $8 million for the three months ended September 30, 2011 compared to $5 million for the three months ended September 30, 2010. Gathering costs per unit increased primarily due to increased third party transportation costs and increased pipeline maintenance charges.

General and administrative costs related to the Conventional gas segment were $8 million for the three months ended September 30, 2011 compared to $7 million for the three months ended September 30, 2010. General and 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 administrative costs increases which were discussed in the CBM segment, combined with the decreased volumes sold contributed to the increased general and administrative costs allocated to the conventional gas segment.

Depreciation, depletion and amortization costs were $15 million for the three months ended September 30, 2011 compared to $23 million for the three months ended September 30, 2010. There was approximately $14 million, or $1.74 per unit-of production, of depreciation, depletion and amortization related to conventional gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended September 30, 2011. There was approximately $21 million, or $2.28 per unit-of-production, of depreciation, depletion and amortization related to conventional gas and related well equipment that was reflected on a units-of-production method of depreciation for the three months ended September 30, 2010. The rate is 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. The decrease in the unit-of-production rate is primarily the result of various acquisition adjustments that were reflected after the 2010 period. There was approximately $1 million, or $0.22 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended September 30, 2011. There was $2 million, or $0.21 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the three months ended September 30, 2010. The decrease is related to various acquisition adjustments and additional infrastructure and equipment placed in service after the 2010 period.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $11 million to the total Company earnings before income tax for the three months ended September 30, 2011 compared to $3 million for the three months ended September 30, 2010.

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced gas Marcellus sales volumes (in billion cubic feet)	8.7	3.3	5.4	163.6 %
Average Marcellus sales price per thousand cubic feet sold	$4.48	$4.66	$(0.18)	(3.9)%
Average Marcellus lifting costs per thousand cubic feet sold	$0.70	$0.41	$0.29	70.7 %
Average Marcellus gathering costs per thousand cubic feet sold	$0.29	$1.03	$(0.74)	(71.8)%
Average Marcellus general & administrative costs per thousand cubic feet sold	$0.53	$0.73	$(0.20)	(27.4)%
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	$1.73	$1.71	$0.02	1.2 %
Total Average Marcellus costs per thousand cubic feet sold	$3.25	$3.88	$(0.63)	(16.2)%
Average Margin for Marcellus	$1.23	$0.78	$0.45	57.7 %

The Marcellus segment sales revenues were $39 million for the three months ended September 30, 2011 compared to $16 million for the three months ended September 30, 2010. The decrease in Marcellus average sales price was the result of lower general market prices combined with various gas swap transactions that matured in the three months ended September 30, 2011. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 3.4 billion cubic feet of our produced Marcellus gas sales volumes for the three months ended September 30, 2011 at an average price of $4.61 per thousand cubic feet. These financial hedges represented 0.4 billion cubic feet of our produced Marcellus gas sales volumes for the three months ended September 30, 2010 at an average price of $5.05 per thousand cubic feet. The increased sales volumes are primarily due to additional wells coming on-line from our on-going drilling program. At September 30, 2011, there were 89 Marcellus Shale wells in production. At September 30, 2010, there were 45 Marcellus Shale wells in production.

Marcellus lifting costs were $6 million for the three months ended September 30, 2011 compared to $1 million for the three months ended September 30, 2010. Lifting costs per unit increased $0.29 per thousand cubic feet sold due to increased fishing services and mechanical scale removal services completed to improve well performance, increased activity on non-operated wells and additional well tending costs as a result of the increased number of wells and an escalation in rates. These increases were partially offset by lower repairs and maintenance costs primarily due to the increased sales volumes.

Marcellus gathering costs were $3 million for the three months ended September 30, 2011 compared to $4 million for the three months ended September 30, 2010. Average gathering costs decreased $0.74 per unit primarily due to the 5.4 billion cubic feet of additional volumes sold.

General and administrative costs on the Marcellus gas segment were $4 million for the three months ended September 30, 2011 compared to $3 million for the three months ended September 30, 2010. General and administrative costs attributable to the total gas division are allocated to the individual gas segments based on a combination of production and employee counts. The total general and administrative costs increases which were discussed in the CBM segment combined with higher volumes of Marcellus gas sold contributed to the increase. General and administrative costs were $0.53 per thousand cubic feet sold for the three months ended September 30, 2011 compared to $0.73 per thousand cubic feet sold for the three months ended September 30, 2010.

Depreciation, depletion and amortization costs were $15 million for the three months ended September 30, 2011 compared to $5 million for the three months ended September 30, 2010. There was approximately $10 million, or $1.13 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 three months ended September 30, 2011. There was approximately $5 million, or $1.50 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 three months ended September 30, 2010. The rate is 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 $5 million, or $0.60 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis in the three months ended September 30, 2011. There was less than $1 million, or $0.21 per thousand cubic feet, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis in the three months ended September 30, 2010. The increase is 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 $3 million for the three months ended September 30, 2011 and $1 million for the three months ended September 30, 2010. Total costs related to these other sales were $4 million in the 2011 period and were $2 million in the 2010 period. The increase in costs in the period-to-period comparison was primarily attributable to additional general and administrative costs, which are discussed in the CBM segment. 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 segment. Royalty interest gas sales revenue was $17 million for the three months ended September 30, 2011 compared to $19 million for the three months ended September 30, 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 Three Months Ended September 30,			
	2011	2010	Variance	Percent

					Change	
Gas Royalty Interest Sales Volumes (in billion cubic feet)	3.9	4.1	(0.2	)	(4.9	)%
Average Sales Price Per thousand cubic feet	$4.34	$4.43	$(0.09	)	(2.0	)%

Purchased gas sales volumes represent volumes of gas we sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $1 million for the three months ended September 30, 2011 compared to $3 million for the three months ended September 30, 2010.

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	0.3	0.6	(0.3)	(50.0)%
Average Sales Price Per thousand cubic feet	$4.43	$5.54	$(1.11)	(20.0)%

Other income was a loss of $14 million for the three months ended September 30, 2011 compared to income of $2 million for the three months ended September 30, 2010. The decrease was primarily due to the loss on the Noble transaction of $58 million. This loss was partially offset by a gain on the sale of the Antero overriding royalty interest of $41 million and $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

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 $16 million for the three months ended September 30, 2011 compared to $17 million for the three months ended September 30, 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 Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	3.9	4.1	(0.2)	(4.9)%
Average Cost Per thousand cubic feet sold	$3.92	$4.01	$(0.09)	(2.2)%

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 less than $1 million in the three months ended September 30, 2011 and $3 million in the three months ended September 30, 2010.

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	0.2	0.6	(0.4)	(66.7)%
Average Cost Per thousand cubic feet sold	$1.62	$5.49	$(3.87)	(70.5)%

Exploration and other costs were $6 million for the three months ended September 30, 2011 compared to $12 million for the three months ended September 30, 2010. The $6 million decrease is primarily related to increased lease surrenders and additional dry wells in the 2010 period. Costs included in the exploration and other cost line are detailed as follows:

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Dry Hole and Lease Expiration Costs	$6	$12	$(6)	(50.0)%
Exploration	—	—	—	—%
Total Exploration and Other Costs	$6	$12	$(6)	(50.0)%

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Other corporate expenses were $20 million for the three months ended September 30, 2011 compared to $13 million for the three months ended September 30, 2010. The $7 million increase in the period-to-period comparison was made up of the following items:

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Short-term incentive compensation	$6	$2	$4	200.0 %
Unutilized firm transportation	5	1	4	400.0 %
Contract buyout	3	—	3	100.0 %
Stock-based compensation	4	4	—	— %
Other	2	6	(4)	(66.7)%
Total Other Corporate Expenses	$20	$13	$7	53.8 %

- The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for safety, production and unit costs. Short-term incentive compensation increased in the period-to-period comparison as the result of exceeding the targets in the 2011 period and an increased allocation of expense from CONSOL Energy as the result of exceeding corporate targets.

- Unutilized firm transportation represents excess pipeline transportation capacity that the gas division obtained to enable gas production to flow on an uninterrupted basis as the gas operations continue to increase sales volumes.

- Contract buyout represents the cancellation of a drilling arrangement with a third-party well driller.

- Stock-based compensation expense remained consistent in the period-to-period comparison.

- Other corporate related expense decreased $4 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense related to the other gas segment remained consistent at $2 million for both the three months ended September 30, 2011 and 2010. Interest was incurred by the other gas segment on the CNX Gas revolving credit facility, a capital lease and debt held by a variable interest entity.

Noncontrolling interest represents 100% of the earnings impact of a third party which has been determined to be a variable interest entity, in which CONSOL Energy holds no ownership interest, but is the primary beneficiary. The CONSOL Energy gas division has been determined to be the primary beneficiary due to guarantees of the third party's bank debt related to their purchase of drilling rigs. The third-party entity provides drilling services primarily to the CONSOL Energy gas division. CONSOL Energy consolidates the entity and then reflects 100% of the impact as noncontrolling interest. The consolidation does not significantly impact any amounts reflected in the gas division income statement. The variance in the noncontrolling amounts reflects the third party's variance in earnings in the period-to-period comparison. In the three months ended September 30, 2011, the drilling services contract was bought out. Subsequent to this transaction, the non-controlling interest was de-consolidated.

OTHER SEGMENT ANALYSIS for the three months ended September 30, 2011 compared to the three months ended September 30, 2010:

The other segment includes activity from the sales of industrial supplies, the transportation operations and various other corporate activities that are not allocated to the coal or gas segment. The other segment had a loss before income tax of $68 million for the three months ended September 30, 2011 compared to a loss before income tax of $63 million for the three months ended September 30, 2010. The other segment also included total company income tax expense of $33 million for the three months ended September 30, 2011 compared to $16 million for the three months ended September 30, 2010.

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Sales—Outside	$88	$75	$13	17.3 %
Other Income	7	5	2	40.0 %
Total Revenue	95	80	15	18.8 %
Cost of Goods Sold and Other Charges	98	72	26	36.1 %
Depreciation, Depletion & Amortization	5	4	1	25.0 %
Taxes Other Than Income Tax	3	3	—	— %
Interest Expense	57	64	(7)	(10.9)%
Total Costs	163	143	20	14.0 %
Loss Before Income Tax	(68)	(63)	(5)	(7.9)%
Income Tax	33	16	17	106.3 %
Net Loss	$(101)	$(79)	$(22)	(27.8)%

Industrial supplies:

Total revenue from industrial supplies was $63 million for the three months ended September 30, 2011 compared to $48 million for the three months ended September 30, 2010. The increase was primarily related to higher sales volumes.

Total costs related to industrial supply sales were $59 million for the three months ended September 30, 2011 compared to $46 million for the three months ended September 30, 2010. The increase of $13 million was primarily related to higher sales volumes.

Transportation operations:

Total revenue from transportation operations was $29 million for the three months ended September 30, 2011 compared to $30 million for the three months ended September 30, 2010. The decrease of $1 million was primarily attributable to less through-put tons at the Baltimore terminal in the period-to-period comparison.

Total costs related to the transportation operations were $22 million for the three months ended September 30, 2011 compared to $21 million for the three months ended September 30, 2010. The increase of $1 million was primarily related to repairs and maintenance costs to maintain the Baltimore terminal facilities, none of which were individually material.

Miscellaneous other:

Additional other income of $3 million was recognized for the three months ended September 30, 2011 compared to $2 million for the three months ended September 30, 2010. The $1 million decrease was primarily due to lower equity in earnings of affiliates in the current period compared to the prior year period and various transactions that occurred throughout both periods, none of which were individually material.

Other corporate costs in the other segment include interest expense, acquisition and financing costs and various other miscellaneous corporate charges. Total other costs were $82 million for the three months ended September 30, 2011 compared to $76 million for the three months ended September 30, 2010. Other corporate costs increased due to the following items:

	For the Three Months Ended September 30,		
	2011	2010	Variance
Transaction and financing fees	$15	$—	$15
Interest expense	57	64	(7)
Bank fees	6	7	(1)
Evaluation fees for non-core asset dispositions	2	2	—
Other	2	3	(1)
	$82	$76	$6

- Transaction and financing fees of $15 million incurred in the three months ended September 30, 2011 related to the solicitation of consents of the long-term bonds needed in order to clarify the indentures that relate to joint arrangements with respect to CONSOL Energy's oil and gas properties.
- Interest expense decreased $7 million in the period-to-period comparison primarily due to uncertain tax position adjustments related to the closure of federal income tax audits and lower borrowings on the revolving credit facility.
- Bank fees decreased $1 million due to less borrowings on the revolving credit facility in the period-to-period comparison.
- Evaluation fees for non-core asset dispositions remained consistent in the period-to-period comparison.
- Other corporate items decreased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 16.5% in the three months ended September 30, 2011 compared to 17.3% in the three months ended September 30, 2010. The effective income tax rate was impacted by several discrete transactions that occurred in both the three months ended September 30, 2011 and 2010. The discrete items in 2011 included the results from the 2006 and 2007 Internal Revenue Service Revenue Agent's Report and related impacts on the 2010 accrual. The adjustments were primarily due to capital versus expense items and the related percentage depletion impacts. The relationship between pre-tax earnings and percentage depletion also impacts the effective tax rate. See Note 5—Income Taxes of the Notes to the Condensed Consolidated Financial Statements of this Form 10-Q for additional information.

	For the Three Months Ended September 30,			
	2011	2010	Variance	Percent Change
Total Company Earnings Before Income Tax	$200	$91	$109	119.8 %
Income Tax Expense	$33	$16	$17	106.3 %
Effective Income Tax Rate	16.5 %	17.3 %	(0.8)%	

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Results of Operations
Nine Months Ended September 30, 2011 Compared with Nine Months Ended September 30, 2010

Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $437 million, or $1.91 per diluted share, for the nine months ended September 30, 2011. Net income attributable to CONSOL Energy shareholders was $242 million, or $1.13 per diluted share, for the nine months ended September 30, 2010.
The coal division includes steam coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $719 million of earnings before income tax for the nine months ended September 30, 2011 compared to $349 million for the nine months ended September 30, 2010. The total coal division sold 47.5 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, for the nine months ended September 30, 2011 compared to 46.2 million tons for the nine months ended September 30, 2010.
The average sales price and average costs per ton for all active coal operations were as follows:

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Average Sales Price per ton sold	$72.48	$61.42	$11.06	18.0 %
Average Costs per ton sold	51.39	47.44	3.95	8.3 %
Margin	$21.09	$13.98	$7.11	50.9 %

The higher average sales price per ton sold reflects successful re-negotiation of several domestic steam contracts whose pricing took effect January 1, 2011, another strong quarter of high volatile metallurgical coal sales and continued demand for our premium low volatile metallurgical coal. Also, 8.6 million tons were sold on the export market at an average sales price of $124.54 per ton for the nine months ended September 30, 2011 compared to 5.9 million tons at an average price of $97.46 per ton for the nine months ended September 30, 2010.

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

- Depreciation, depletion and amortization increased due to additional assets placed into service after the 2010 period,
- Operating supplies and maintenance costs per ton sold were higher due to additional roof control costs, additional maintenance costs and equipment overhaul costs,
- Higher costs associated with the increased sales price of coal sold, such as royalties and production related taxes,
- Increased actuarial expenses related to other post employment benefits and pension related to employees retiring sooner than originally anticipated and average claim costs being higher than originally anticipated, and
- Increased labor and labor related charges 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 new UMWA contract.

The total gas division includes coalbed methane (CBM), conventional, Marcellus and other gas. The total gas division contributed $53 million of earnings before income tax for the nine months ended September 30, 2011 compared to $163 million for the nine months ended September 30, 2010. Total gas production was 113.8 billion cubic feet for the nine months ended September 30, 2011 compared to 91.7 billion cubic feet for the nine months ended September 30, 2010.
The average sales price and average costs for all active gas operations were as follows:

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$4.97	$6.22	$(1.25)	(20.1)%
Average Costs per thousand cubic feet sold	3.86	3.88	(0.02)	(0.5)%

Margin	$ 1.11	$ 2.34	$ (1.23)	(52.6)%

Total gas division outside sales revenues were $566 million for the nine months ended September 30, 2011 compared to $571 million for the nine months ended September 30, 2010. The decrease was primarily due to the 20.1% reduction in average price per thousand cubic feet sold partially offset by the 24.1% increase in volumes sold. 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 60.1 billion cubic feet of our produced gas sales volumes for the nine months ended September 30, 2011 at an average price of $5.23 per thousand cubic feet. These financial hedges represented 40.1 billion cubic feet of our produced gas sales volumes for the nine months ended September 30, 2010 at an average price of $8.09 per thousand cubic feet.

Total gas unit costs decreased slightly for the nine months ended September 30, 2011 compared to the nine months ended September 30, 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, which closed on April 30, 2011, increased total operating costs by $0.43 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 $0.45 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, which occurred on April 30, 2010. 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 unutilized firm transportation charges now being reflected in other corporate expenses. Lifting costs increased in the period-to-period comparison due to additional well services related to the increased number of wells and escalation in rates.

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. A detailed analysis of these total Company expenses are as follows:

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 Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Employee wages and related expenses	$60	$52	$8	15.4 %
Advertising and promotion	7	2	5	250.0 %
Contributions	5	3	2	66.7 %
Commissions	11	10	1	10.0 %
Consulting and professional services	20	19	1	5.3 %
Miscellaneous	27	22	5	22.7 %
Total Company Selling, General and Administrative Expenses	$130	$108	$22	20.4 %

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.
- Advertising and promotion expense increased $5 million in the period-to-period comparison due to additional campaigns initiated in the 2011 period.
- Contributions expense increased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.
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Commission expense increased $1 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 $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

- Miscellaneous selling, general and administrative expenses increased $5 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 $249 million for the nine months ended September 30, 2011 compared to $216 million for the nine months ended September 30, 2010. The increase of $33 million was due primarily to OPEB and salary pension expense. The additional OPEB and salary pension expense related to employees retiring sooner than originally anticipated and average claim costs being higher than originally anticipated. Also, higher provision expenses in the period-to-period comparison were due to changes in the discount rates used at the measurement date, which is December 31. See Note 3—Components of Pension and Other Postretirement Benefit Plans Net Periodic Benefit Costs and Note 4—Components of Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation Net Periodic Benefit Costs in the Notes to the Unaudited Consolidated Financial Statements for additional detail of total Company expense increases.

TOTAL COAL SEGMENT ANALYSIS for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010:

The coal segment contributed $719 million of earnings before income tax in the nine months ended September 30, 2011 compared to $349 million in the nine months ended September 30, 2010. Variances by the individual coal segments are discussed below.

	For the Nine Months Ended September 30, 2011					Difference to Nine Months Ended September 30, 2010				
	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$2,315	$278	$824	$23	$3,440	$112	$143	$333	$16	$604
Purchased Coal	—	—	—	38	38	—	—	—	12	12
Total Outside Sales	2,315	278	824	61	3,478	112	143	333	28	616
Freight Revenue	—	—	—	156	156	—	—	—	59	59
Other Income	5	9	—	52	66	—	3	—	11	14
Total Revenue and Other Income	2,320	287	824	269	3,700	112	146	333	98	689
Costs and Expenses:										
Total operating costs	1,429	126	223	170	1,948	(8)	73	50	10	125
Total provisions	165	15	28	44	252	16	9	8	(69)	(36)
Total administrative & other costs	127	13	21	63	224	19	9	7	(6)	29
Depreciation, depletion and amortization	226	22	27	126	401	28	14	12	88	142
Total Costs and Expenses	1,947	176	299	403	2,825	55	105	77	23	260
Freight Expense	—	—	—	156	156	—	—	—	59	59
Total Costs	1,947	176	299	559	2,981	55	105	77	82	319
Earnings (Loss) Before Income Taxes	$373	$111	$525	$(290)	$719	$57	$41	$256	$16	$370

STEAM COAL SEGMENT

The steam coal segment contributed $373 million to total Company earnings before income tax for the nine months ended September 30, 2011 compared to $316 million for the nine months ended September 30, 2010. The steam coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Nine Months Ended June 30,			
	2011	2010	Variance	Percent Change
Produced Steam Tons Sold (in millions)	39.3	40.7	(1.4)	(3.4)%
Average Sales Price Per Steam Ton Sold	$58.88	$54.09	$4.79	8.9 %
Average Operating Costs Per Steam Ton Sold	$36.33	$35.29	$1.04	2.9 %
Average Provision Costs Per Steam Ton Sold	$4.21	$3.66	$0.55	15.0 %
Average Selling, Administrative and Other Costs Per Steam Ton Sold	$3.23	$2.65	$0.58	21.9 %
Average Depreciation, Depletion and Amortization Costs Per Steam Ton Sold	$5.76	$4.85	$0.91	18.8 %
Total Average Costs Per Steam Ton Sold	$49.53	$46.45	$3.08	6.6 %
Margin Per Steam Ton Sold	$9.35	$7.64	$1.71	22.4 %

Steam coal revenue was $2,315 million for the nine months ended September 30, 2011 compared to $2,203 million for the nine months ended September 30, 2010. The $112 million increase was attributable to a $4.79 per ton higher average sales price partially offset by 1.4 million fewer tons sold. The higher average steam coal sales price in the 2011 period was the result of successful re-negotiation of several domestic steam contracts whose pricing took effect on January 1, 2011. Also, 1.8 million tons of steam coal was sold on the export market at an average sales price of $68.15 per ton for the nine months ended September 30, 2011 compared to 1.5 million tons at an average price of $55.31 per ton for the nine months ended September 30, 2010. The steam coal segment was also impacted by 3.5 million tons of steam coal sold on the high volatile metallurgical coal market for the nine months ended September 30, 2011, which increased 1.7 million tons compared to the nine months ended September 30, 2010.

Other income attributable to the steam coal segment represents earnings from our equity affiliates that operate steam 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 steam coal segment were $1,429 million for the nine months ended September 30, 2011 compared to $1,437 million for the nine months ended September 30, 2010. Operating costs related to the steam coal segment decreased primarily due to higher average costs per ton sold partially offset by lower volumes sold.

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

- Average operating supplies & maintenance costs per ton sold increased due to additional maintenance and equipment overhaul costs and additional roof control costs. 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 preparation costs per ton sold increased due to additional maintenance projects completed at our preparation plants in the period-to-period comparison.
- Labor and related benefits were impaired on a cost per 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. Contributions 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.

Additional employees in the period-to-period comparison also contributed to higher labor costs. Non-union 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 new collective bargaining agreement, in the period-to-period comparison. 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 ton sold increased primarily due to the $4.79 per ton higher average sales price.
- Average operating costs per steam ton sold increased due to lower tons sold as fixed costs were allocated over less tons; therefore, unit cost increased.

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 steam coal segment were $165 million for the nine months ended September 30, 2011 compared to $149 million for the nine months ended September 30, 2010. The increased steam coal provision expense was attributable to the total Company increase in long-term liability expense discussed in the total Company results of operations section. Steam 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 steam 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 segment 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 steam coal segment were $127 million for the nine months ended September 30, 2011 compared to $108 million for the nine months ended September 30, 2010. The cost increases attributable to the steam 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 additional safety reward expense in the period-to-period comparison. These higher costs and lower sales volumes resulted in a $0.58 per ton increase in average cost per ton sold.
Depreciation, depletion and amortization for the steam coal segment was $226 million for the nine months ended September 30, 2011 compared to $198 million for the nine months ended September 30, 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 steam 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 $111 million to total Company earnings before income tax for the nine months ended September 30, 2011 compared to $70 million for the nine months ended September 30, 2010. The high volatile metallurgical coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced High Vol Met Tons Sold (in millions)	3.5	1.8	1.7	94.4 %
Average Sales Price Per High Vol Met Ton Sold	$78.75	$73.65	$5.10	6.9 %
Average Operating Costs Per High Vol Met Ton Sold	$35.98	$28.89	$7.09	24.5 %
Average Provision Costs Per High Vol Met Ton Sold	$4.15	$3.08	$1.07	34.7 %
Average Selling, Administrative and Other Costs Per High Vol Met Ton Sold	$3.63	$2.26	$1.37	60.6 %
Average Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Sold	$6.25	$4.24	$2.01	47.4 %
Total Average Costs Per High Vol Met Ton Sold	$50.01	$38.47	$11.54	30.0 %
Margin Per High Vol Met Ton Sold	$28.74	$35.18	$(6.44)	(18.3 %)

High volatile metallurgical coal revenue was $278 million for the nine months ended September 30, 2011 compared to $135 million for the nine months ended September 30, 2010. Strength in the metallurgical coal market has continued to allow the export of Northern Appalachian coal, historically sold domestically on the steam coal market, to crossover to the Brazilian and Asian metallurgical coal markets. 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 $126 million for the nine months ended September 30, 2011 compared to $53 million for the nine months ended September 30, 2010. Operating costs related to the high volatile metallurgical coal segment increased primarily due to higher average costs per ton sold and higher volumes 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 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-union 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-union benefit rates for active employees related to the continued increase in healthcare costs. Higher contributions made to the Trust were discussed in the steam coal segment. 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 new 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 steam 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 & maintenance costs per ton sold increased due to additional maintenance and equipment overhaul costs and additional roof control costs. Additional maintenance and equipment overhaul costs were 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. Roof control costs also increased due to higher steel prices in the period-to-period comparison.
- Average coal preparation costs per 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 ton sold increased due to the $5.10 per ton higher average sales price.
- In-transit charges average cost per 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.
- Subsidence costs per ton sold increased due to more structures and higher costs related to these structures that were impacted by longwall mining in the period-to-period comparison. Subsidence costs also increased due to an increase in the length of streams that were impacted by longwall mining in the period-to-period comparison.
- Average operating costs per ton sold decreased due to higher tons sold. Therefore, fixed costs were allocated over more tons; therefore, unit costs decreased.

The provision expense attributable to the high volatile metallurgical coal segment was $15 million for the nine months ended September 30, 2011 compared to $6 million for the nine months ended September 30, 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 contributed to lower 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 segment 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 $13 million for the nine months ended September 30, 2011 compared to $4 million for the nine months ended September 30, 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 are primarily due to additional safety reward expense in the period-to-period comparison. These increases in expense 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 $22 million for the nine months ended September 30, 2011 compared to $8 million for the nine months ended September 30, 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 steam coal market.

LOW VOL METALLURGICAL COAL SEGMENT

The low volatile metallurgical coal segment contributed $525 million to total Company earnings before income tax in the nine months ended September 30, 2011 compared to $269 million in the nine months ended September 30, 2010. The low volatile metallurgical coal revenue and cost components on a per ton basis for these periods are as follows:

	For the Nine Months Ended September 30,				
	2011	2010	Variance	Percent Change	
Produced Low Vol Met Tons Sold (in millions)	4.3	3.5	0.8	22.9	%
Average Sales Price Per Low Vol Met Ton Sold	$ 191.84	$ 140.27	$ 51.57	36.8	%
Average Operating Costs Per Low Vol Met Ton Sold	$ 51.84	$ 49.44	$ 2.40	4.9	%
Average Provision Costs Per Low Vol Met Ton Sold	$ 6.63	$ 5.80	$ 0.83	14.3	%
Average Selling, Administrative and Other Costs Per Low Vol Met Ton Sold	$ 4.88	$ 3.96	$ 0.92	23.2	%
Average Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Sold	$ 6.30	$ 4.35	$ 1.95	44.8	%
Total Average Costs Per Low Vol Met Ton Sold	$ 69.65	$ 63.55	$ 6.10	9.6	%
Margin Per Low Vol Met Ton Sold	$ 122.19	$ 76.72	$ 45.47	59.3	%

Low volatile metallurgical coal revenue was $824 million for the nine months ended September 30, 2011 compared to $491 million for the nine months ended September 30, 2010. The $333 million increase was attributable to a $51.57 per ton higher average sales price due to the continued strengthening of the low volatile metallurgical market, both domestic and foreign. The continued strength of these markets is related to continued worldwide demand for premium low volatile metallurgical coal. For the 2011 period, 3.6 million tons of low volatile metallurgical coal was sold on the export market at an average price of $195.38 per ton compared to 2.6 million tons at an average price of $138.41 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 $223 million for the nine months ended September 30, 2011 compared to $173 million for the nine months ended September 30, 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:

- Average operating supplies and maintenance costs per ton sold increased due to additional roof control costs, additional ventilation costs of coalbed methane gas and additional equipment overhaul costs. Additional roof control costs resulted from changes in roof support strategy, such as types of roof support used and quantity of support 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. Additional 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.
- Costs associated with the sales price of coal sold, such as royalties and production related taxes, increased due to the higher average sales prices received for low volatile metallurgical coal in the period-to-period comparison.

The provision expense attributable to the low volatile metallurgical coal segment was $28 million for the nine months ended September 30, 2011 compared to $20 million for the nine months ended September 30, 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 segment 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 $21 million for the nine months ended September 30, 2011 compared to $14 million for the nine months ended September 30, 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 $27 million for the nine months ended September 30, 2011 compared to $15 million for the nine months ended September 30, 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. The increase was also due to higher units-of-production rates due to additional air shafts being placed into service during the 2010 period which had higher unit rates than historical shafts put into service. 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 $290 million for the nine months ended September 30, 2011 compared to a loss before income tax of $306 million for the nine months ended September 30, 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 0.3 million tons of coal which was recovered during the reclamation process at idled facilities for the nine months ended September 30, 2011 and 0.1 million tons for the nine months ended September 30, 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 $38 million for the nine months ended September 30, 2011 compared to $26 million for the nine months ended September 30, 2010. The increase was primarily due to increased volumes sold.

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 offset in freight expense. Freight revenue was $156 million for the nine months ended September 30, 2011 compared to $97 million for the nine months ended September 30, 2010. The increase in freight revenue was primarily due to the 2.7 million ton increase in export tons in the period-to-period comparison.

Miscellaneous other income was $52 million for the nine months ended September 30, 2011 compared to $41 million for the nine months ended September 30, 2010. The increase of $11 million was primarily related to issuing pipeline right-of-ways to a third party which resulted in a gain of $10 million and $1 million of various other transactions that occurred throughout both periods, none of which were individually material.

Other coal segment total costs were $559 million for the nine months ended September 30, 2011 compared to $477 million for the nine months ended September 30, 2010. The increase of $82 million was due to the following items:

	For the Nine Months Ended September 30,		
	2011	2010	Variance
Abandonment of long-lived assets	$116	$—	$116
Freight expense	156	97	59
Purchased Coal	59	30	29
Coal contract buyout	5	—	5
Closed and idle mines	80	184	(104)
Litigation expense	—	35	(35)
Other	143	131	12
Total other coal segment costs	$559	$477	$82

- Abandonment of long-lived assets was $116 million for the nine months ended September 30, 2011 as a result of the decision to permanently idle 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 offset in freight revenue. The increase was primarily due to the 2.7 million ton increase in export tons in the period-to-period comparison.
- Purchased coal costs increased approximately $29 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 on a higher priced contract in a future period.
- Closed and idle mine costs decreased approximately $104 million in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. In the 2010 period, as a result of market conditions, permitting issues, new regulatory requirements and resulting changes in mining plans, the reclamation liability associated with the Fola mining operations in West Virginia was 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. In addition, $8 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
- Litigation expense of $25 million was recognized in the nine months ended September 30, 2010 related to an anticipated 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 nine months ended September 30, 2010 related to a settlement that included the sale of Jones Fork which resulted in a loss of $10 million.
- Other expenses related to the coal segment were $12 million higher for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. The increase was related to a $5 million charge for an additional liability due to Pennsylvania stream remediation and $7 million of the increase was related to various transactions that occurred throughout both periods, none of which were individually material.

TOTAL GAS SEGMENT ANALYSIS for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010:

The gas segment contributed $53 million to earnings before income tax in the nine months ended September 30, 2011 compared to $163 million in the nine months ended September 30, 2010.

	For the Nine Months Ended September 30, 2011					Difference to Nine Months Ended September 30, 2010				
	CBM	Conven-tional	Marcellus	Other Gas	Total Gas	CBM	Conven-tional	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$345	$120	$88	$9	$562	$(104)	$42	$54	$4	$(4)
Related Party	4	—	—	—	4	(1)	—	—	—	(1)
Total Outside Sales	349	120	88	9	566	(105)	42	54	4	(5)
Gas Royalty Interest	—	—	—	52	52	—	—	—	5	5
Purchased Gas	—	—	—	3	3	—	—	—	(5)	(5)
Other Income	—	—	—	(9)	(9)	—	—	—	(12)	(12)
Total Revenue and Other Income	349	120	88	55	612	(105)	42	54	(8)	(17)
Lifting	38	43	12	2	95	(1)	25	9	1	34
Gathering	71	20	10	2	103	(3)	12	2	—	11
General & Administration	46	23	12	1	82	(1)	11	7	2	19
Depreciation, Depletion and Amortization	75	48	29	7	159	(8)	9	16	2	19
Gas Royalty Interest	—	—	—	47	47	—	—	—	6	6
Purchased Gas	—	—	—	3	3	—	—	—	(4)	(4)
Exploration and Other Costs	—	—	—	10	10	—	—	—	(11)	(11)
Other Corporate Expenses	—	—	—	49	49	—	—	—	9	9
Interest Expense	—	—	—	7	7	—	—	—	1	1
Total Cost	230	134	63	128	555	(13)	57	34	6	84
Earnings Before Noncontrolling Interest and Income Tax	119	(14)	25	(73)	57	(92)	(15)	20	(14)	(101)
Noncontrolling Interest	—	—	—	4	4	—	—	—	9	9
Earnings Before Income Tax	$119	$(14)	$25	$(77)	$53	$(92)	$(15)	$20	$(23)	$(110)

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $119 million to the total Company earnings before income tax for the nine months ended September 30, 2011 compared to $211 million for the nine months ended September 30, 2010.

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced gas CBM sales volumes (in billion cubic feet)	68.6	67.7	0.9	1.3 %
Average CBM sales price per thousand cubic feet sold	$ 5.09	$ 6.70	$ (1.61)	(24.0)%
Average CBM lifting costs per thousand cubic feet sold	$ 0.56	$ 0.57	$ (0.01)	(1.8)%
Average CBM gathering costs per thousand cubic feet sold	$ 1.04	$ 1.09	$ (0.05)	(4.6)%
Average CBM general & administrative costs per thousand cubic feet sold	$ 0.67	$ 0.69	$ (0.02)	(2.9)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	$ 1.09	$ 1.23	$ (0.14)	(11.4)%
Total Average CBM costs per thousand cubic feet sold	$ 3.36	$ 3.58	$ (0.22)	(6.1)%
Average Margin for CBM	$ 1.73	$ 3.12	$ (1.39)	(44.6)%

CBM sales revenues were $349 million for the nine months ended September 30, 2011 compared to $454 million for the nine months ended September 30, 2010. The $105 million decrease was primarily due to a 24.0% decrease in average sales price per thousand cubic feet sold, offset, in part, by a 1.3% 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 45.1 billion cubic feet of our produced CBM gas sales volumes for the nine months ended September 30, 2011 at an average price of $5.37 per thousand cubic feet. For the nine months ended September 30, 2010, these financial hedges represented 39.7 billion cubic feet at an average price of $8.12 per thousand cubic feet. CBM sales volumes increased 0.9 billion cubic feet primarily due to additional wells coming on-line from our on-going drilling program.

Total costs for the CBM segment were $230 million for the nine months ended September 30, 2011 compared to $243 million for the nine months ended September 30, 2010. Lower costs in the period-to-period comparison are primarily related to increased volumes sold offset, in part, by lower unit costs.

CBM lifting costs were $38 million for the nine months ended September 30, 2011 compared to $39 million for the nine months ended September 30, 2010. Lifting costs decreased slightly in the period-to-period comparison due primarily to the increased volumes sold.

CBM gathering costs were $71 million for the nine months ended September 30, 2011 compared to $74 million for the nine months ended September 30, 2010. Lower average CBM gathering unit costs are related to lower fuel surcharges and unutilized firm transportation being reported in other corporate expenses in the 2011 period.

General and administrative costs attributable to the total gas division were $82 million for the nine months ended September 30, 2011 compared to $63 million for the nine months ended September 30, 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 administrative costs for the CBM segment were $46 million in the nine months ended September 30, 2011 compared to $47 million for the nine months ended September 30, 2010. General and 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 consistent general and administrative costs attributable to the CBM segment coupled with higher volumes of CBM sold resulted in lower unit costs in the period-to-period comparison.

Depreciation, depletion and amortization attributable to the CBM segment was $75 million for the nine months ended September 30, 2011 compared to $83 million for the nine months ended September 30, 2010. There was approximately $53 million, or $0.77 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 nine months ended September 30, 2011.

The production portion of depreciation, depletion and amortization was $64 million, or $0.95 per unit-of-production in the nine months ended September 30, 2010. The CBM unit-of-production rate decreased due to revised rates which are generally calculated using the net book value of assets divided by either proved or proved developed reserve additions. There was approximately $22 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 nine months ended September 30, 2011. The non-production related depreciation, depletion and amortization was $19 million, or $0.28 per thousand cubic feet for the nine months ended September 30, 2010. The increase was related to additional gathering assets placed in service after the 2010 period.

CONVENTIONAL GAS SEGMENT

The conventional segment had a loss before income tax of $14 million for the nine months ended September 30, 2011 compared to $1 million of earnings before income tax for the nine months ended September 30, 2010.

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced gas Conventional sales volumes (in billion cubic feet)	24.0	15.9	8.1	50.9 %
Average Conventional sales price per thousand cubic feet sold	$5.00	$4.91	$0.09	1.8 %
Average Conventional lifting costs per thousand cubic feet sold	$1.79	$1.12	$0.67	59.8 %
Average Conventional gathering costs per thousand cubic feet sold	$0.84	$0.54	$0.30	55.6 %
Average Conventional general & administrative costs per thousand cubic feet sold	$0.97	$0.74	$0.23	31.1 %
Average Conventional depreciation, depletion and amortization costs per thousand cubic feet sold	$2.00	$2.45	$(0.45)	(18.4)%
Total Average Conventional costs per thousand cubic feet sold	$5.60	$4.85	$0.75	15.5 %
Average Margin for Conventional	$(0.60)	$0.06	$(0.66)	(1,100.0)%

Conventional sales revenues were $120 million for the nine months ended September 30, 2011 compared to $78 million for the nine months ended September 30, 2010. The $42 million increase was primarily due to the 50.9% increase in volumes sold as well as the 1.8% increase in average sales price. Conventional sales volumes increased 8.1 billion cubic feet in the nine months ended September 30, 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 conventional type wells. Average sales price increased primarily due to quality of natural gas and increased oil prices in the period-to-period comparison. The increase in conventional sales price was also the result of various gas swap transactions that matured in the nine months ended September 30, 2011. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 8.0 billion cubic feet of our produced conventional gas sales volumes for the nine months ended September 30, 2011 at an average price of $4.97 per thousand cubic feet. There were no conventional gas swap transactions that occurred in the nine months ended September 30, 2010.

Total costs for the conventional segment were $134 million for the nine months ended September 30, 2011 compared to $77 million for the nine months ended September 30, 2010. The increase is attributable to increased variable costs associated with the additional sales volumes and higher average unit costs. A detailed analysis of cost categories is not meaningful due to the significant change in this segment related to the Dominion Acquisition.

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $25 million to the total Company earnings before income tax for the nine months ended September 30, 2011 compared to $5 million for the nine months ended September 30, 2010.

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Produced gas Marcellus sales volumes (in billion cubic feet)	19.7	7.1	12.6	177.5 %
Average Marcellus sales price per thousand cubic feet sold	$4.48	$4.79	$(0.31)	(6.5)%
Average Marcellus lifting costs per thousand cubic feet sold	$0.63	$0.47	$0.16	34.0 %
Average Marcellus gathering costs per thousand cubic feet sold	$0.49	$1.07	$(0.58)	(54.2)%
Average Marcellus general & administrative costs per thousand cubic feet sold	$0.63	$0.67	$(0.04)	(6.0)%
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	$1.48	$1.88	$(0.40)	(21.3)%
Total Average Marcellus costs per thousand cubic feet sold	$3.23	$4.09	$(0.86)	(21.0)%
Average Margin for Marcellus	$1.25	$0.70	$0.55	78.6 %

The Marcellus segment sales revenues were $88 million for the nine months ended September 30, 2011 compared to $34 million for the nine months ended September 30, 2010. The $54 million increase was primarily due to a 177.5% increase in average volumes sold, offset, in part, by a 6.5% decrease in average sales price per thousand cubic feet sold. 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 nine months ended September 30, 2011. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 6.8 billion cubic feet of our produced Marcellus gas sales volumes for the nine months ended September 30, 2011 at an average price of $4.60 per thousand cubic feet. For the nine months ended September 30, 2010, these financial hedges represented 0.4 billion cubic feet at an average price of $5.05 per thousand cubic feet. The increase in sales volumes is primarily due to additional wells coming on-line from our on-going drilling program. At September 30, 2011, there were 89 Marcellus Shale wells in production. At September 30, 2010, there were 45 Marcellus Shale wells in production.

Marcellus lifting costs were $12 million for the nine months ended September 30, 2011 compared to $3 million for the nine months ended September 30, 2010. Lifting costs per unit increased $0.16 per thousand cubic feet sold primarily due to increased expenses for fishing services and mechanical scale removal performed to improve production, increased non-operated well costs, and increased well tending due to an increased number of wells and escalation of rates. These improvements were partially offset by lower salt water disposition costs due to re-utilizing water produced for hydraulic fracing and improved repairs and maintenance primarily as a result of increased sales volumes.

Marcellus gathering costs were $10 million for the nine months ended September 30, 2011 compared to $8 million for the nine months ended September 30, 2010. Average gathering costs decreased $0.58 per unit primarily due to the 12.6 billion cubic feet of additional volumes sold.

General and administrative costs for the Marcellus gas segment were $12 million for the nine months ended September 30, 2011 compared to $5 million for the nine months ended September 30, 2010. General and 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 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 administrative costs were $0.63 per thousand cubic feet sold for the nine months ended September 30, 2011 compared to $0.67 per thousand cubic feet sold for the nine months ended September 30, 2010.

Depreciation, depletion and amortization costs were $29 million for the nine months ended September 30, 2011 compared to $13 million for the nine months ended September 30, 2010. There was approximately $22 million, or $1.08 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 nine months ended September 30, 2011. There was approximately $12 million, or $1.70 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 nine months ended September 30, 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 $0.40 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 nine months ended September 30, 2011. There was $1 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 nine months ended September 30, 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 $9 million for the nine months ended September 30, 2011 and $5 million for the nine months ended September 30, 2010. Total costs related to these other sales were $12 million for the 2011 period and were $7 million for the 2010 period. The increase in costs in the period-to-period comparison were primarily attributable to depreciation, depletion and amortization and increased lifting and gathering costs. Higher depreciation, depletion and amortization was due to higher volumes produced and higher unit of production rates. Increased lifting costs were primarily attributable to increased non-operated shale wells in the period-to-period comparison. Increased gathering costs were attributable to the increased sales volumes. 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 segment. Royalty interest gas sales revenue was $52 million for the nine months ended September 30, 2011 compared to $47 million for the nine months ended September 30, 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 Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	12.2	9.9	2.3	23.2 %
Average Sales Price Per thousand cubic feet	$4.27	$4.69	$(0.42)	(9.0)%

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $3 million for the nine months ended September 30, 2011 compared to $8 million for the nine months ended September 30, 2010.

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	0.7	1.5	(0.8)	(53.3)%
Average Sales Price Per thousand cubic feet	$4.50	$5.65	$(1.15)	(20.4)%

Other income was a loss of $9 million for the nine months ended September 30, 2011 compared to income of $3 million for the nine months ended September 30, 2010. The $12 million decrease was primarily due to a loss on the Noble transaction of $58 million. This loss was partially offset by a gain on the sale of the Antero overriding royalty interest of $41 million, $2 million due to increased earnings from equity affiliates and $3 million due to various transactions that occurred throughout both periods, none of which were individually material.

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 $47 million for the nine months ended September 30, 2011 compared to $41 million for the nine months ended September 30, 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 Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	12.2	9.9	2.3	23.2 %
Average Cost Per thousand cubic feet sold	$3.81	$4.05	$(0.24)	(5.9)%

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 $3 million for the nine months ended September 30, 2011 compared to $7 million for the nine months ended September 30, 2010.

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	0.9	1.3	(0.4)	(30.8)%
Average Cost Per thousand cubic feet sold	$3.11	$5.44	$(2.33)	(42.8)%

Exploration and other costs were $10 million for the nine months ended September 30, 2011 compared to $21 million for the nine months ended September 30, 2010. The $11 million decrease in costs is primarily related to a favorable settlement involving defective pipe which reduced expense in the 2011 period and lower dry hole and lease surrender costs in the 2011 period. Costs included in the exploration and other cost line are detailed as follows:

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Dry Hole and Lease Expiration Costs (including settlement)	$7	$18	$(11)	(61.1)%
Exploration	3	3	—	— %
Total Exploration and Other Costs	$10	$21	$(11)	(52.4)%

Other corporate expenses were $49 million for the nine months ended September 30, 2011 compared to $40 million for the nine months ended September 30, 2010. The $9 million increase in the period-to-period comparison was made up of the following items:

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Unutilized firm transportation	$11	$1	$10	1,000.0 %
Short-term incentive compensation	19	14	5	35.7 %
Contract buyout	3	—	3	100.0 %
Stock-based compensation	13	11	2	18.2 %
Bank fees	5	3	2	66.7 %
Variable interest earnings	(4)	4	(8)	(200.0)%
Legal fees	—	3	(3)	(100.0)%
Other	2	4	(2)	(50.0)%
Total Other Corporate Expenses	$49	$40	$9	22.5 %

- Unutilized firm transportation represents pipeline transportation capacity that the gas segment has obtained to enable gas production to flow uninterrupted as the gas operations continue to increase sales volumes.

- The short-term incentive compensation program is designed to increase compensation to eligible employees when

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CNX Gas reaches predetermined targets for safety, production and unit costs. Short-term incentive compensation increased in the period-to-period comparison as the result of exceeding the targets in the 2011 period, increased number of employees, and an increased allocation of expense from CONSOL Energy as the result of exceeding corporate targets.

- Contract buyout represents the cancellation of a drilling arrangement with a third party well driller.
- Stock-based compensation was higher in the period-to-period comparison primarily due to the increased allocation from CONSOL Energy as a result of the Dominion Acquisition as well as an increase in total CONSOL Energy stock-based compensation expense. Stock-based compensation costs are allocated to the gas segment based on revenue and capital expenditure projections between coal and gas.
- Bank fees were higher in the period-to-period comparison due to amending and extending the revolving credit facility related to the gas segment. In April 2011, the facility was amended to allow $1 billion of borrowings and was extended to April 12, 2016.
- Variable interest earnings are related to various adjustments a third party entity has reflected in its financial statements. CONSOL Energy holds no ownership interest and during the 2011 period de-consolidated the impact of this third party due to the cancellation of the drilling arrangement. Based on analysis, during the time CONSOL Energy guaranteed the bank loans the entity held, it was determined that CONOL Energy was the primary beneficiary. Therefore, the entity was fully consolidated and the earnings impact is fully reversed in the non-controlling interest line discussed below.
- Legal fees for the 2010 period were related to the special committee formed during the CNX Gas take-in transaction and also represent legal fees related to the shareholder litigation related to this transaction.
- Other corporate related expense decreased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense related to the other gas segment was $7 million for the nine months ended September 30, 2011 compared to $6 million for the nine months ended September 30, 2010. Interest was incurred by the other gas segment on the CNX Gas revolving credit facility, a capital lease and debt held by a variable interest entity. The $1 million increase was primarily due to higher levels of borrowings on the revolving credit facility in the period-to-period comparison.

Noncontrolling interest represents 100% of the earnings impact of a third party which has been determined to be a variable interest entity, in which CONSOL Energy holds no ownership interest, but is the primary beneficiary. The CONSOL Energy gas division has been determined to be the primary beneficiary due to guarantees of the third party's bank debt related to their purchase of drilling rigs. The third-party entity provides drilling services primarily to the CONSOL Energy gas division. CONSOL Energy consolidates the entity and then reflects 100% of the impact as noncontrolling interest. The consolidation does not significantly impact any amounts reflected in the gas division income statement. The variance in the noncontrolling amounts reflects the third party's variance in earnings in the period-to-period comparison. In the three months ended September 30, 2011, the drilling services contract was bought out. Subsequent to this transaction, the noncontrolling interest was de-consolidated.

OTHER SEGMENT ANALYSIS for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010:

The other segment includes activity from the sales of industrial supplies, the transportation operations and various other corporate activities that are not allocated to the coal or gas segment. The other segment had a loss before income tax of $222 million for the nine months ended September 30, 2011 compared to a loss before income tax of $184 million for the nine months ended September 30, 2010. The other segment also includes total company income tax expense of $113 million for the nine months ended September 30, 2011 compared to $75 million for the nine months ended September 30, 2010.

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Sales—Outside	$252	$220	$32	14.5 %
Other Income	14	22	(8)	(36.4)%
Total Revenue	266	242	24	9.9 %
Cost of Goods Sold and Other Charges	282	269	13	4.8 %
Depreciation, Depletion & Amortization	14	14	—	— %
Taxes Other Than Income Tax	9	9	—	— %
Interest Expense	183	134	49	36.6 %
Total Costs	488	426	62	14.6 %
Loss Before Income Tax	(222)	(184)	(38)	(20.7)%
Income Tax	113	75	38	50.7 %
Net Loss	$(335)	$(259)	$(76)	(29.3)%

Industrial supplies:

Total revenue from industrial supplies was $172 million for the nine months ended September 30, 2011 compared to $145 million for the nine months ended September 30, 2010. The increase was related to higher sales volumes.

Total costs related to industrial supply sales were $173 million for the nine months ended September 30, 2011 compared to $145 million for the nine months ended September 30, 2010. The increase of $28 million was primarily related to higher sales volumes and last-in, first-out inventory valuations.

Transportation operations:

Total revenue from transportation operations was $88 million for the nine months ended September 30, 2011 compared to $84 million for the nine months ended September 30, 2010. The increase of $4 million was primarily attributable to additional through-put tons at the Baltimore terminal in the period-to-period comparison.

Total costs related to the transportation operations were $66 million for the nine months ended September 30, 2011 compared to $60 million for the nine months ended September 30, 2010. The increase of $6 million was related to the additional through-put tons handled by the operations and repairs and maintenance costs to maintain the Baltimore terminal facilities, none of which were individually material.

Miscellaneous other:

Additional other income of $6 million was recognized for the nine months ended September 30, 2011 compared to $13 million for the nine months ended September 30, 2010. The $7 million decrease was primarily due to the 2010 successful resolution of an outstanding tax issue with the Canadian Revenue Authority for the years 1997 through 2003 in which CONSOL Energy was entitled to interest on a tax refund, lower equity in earnings of affiliates in the current period compared to the prior year period and various transactions that have occurred throughout both periods, none of which were individually material.

Other corporate costs in the other segment include interest expense, transaction and financing fees and various other miscellaneous corporate charges. Total other costs were $249 million for the nine months ended September 30, 2011 compared to $221 million for the nine months ended September 30, 2010. Other corporate costs increased due to the following items:

	For the Nine Months Ended September 30,		
	2011	2010	Variance
Interest expense	$183	$134	$49
Loss on extinguishment of debt	16	—	16
Evaluation fees for non-core asset dispositions	5	2	3
Transaction and financing fees	15	61	(46)
Bank fees	16	13	3
Other	14	11	3
	$249	$221	$28

- Interest expense increased $49 million primarily due to interest expense on the long-term bonds that were issued in conjunction with the Dominion Acquisition in April 2010.
- 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 these notes. 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 $268 million. The loss on extinguishment of debt was $16 million, which primarily represented the interest that would have been paid on these notes if held to maturity.
- Evaluation fees for non-core asset dispositions increased $3 million in the period-to-period comparison due to various corporate initiatives that began in the 2010 period.
- Transaction and financing fees of $61 million incurred in the nine months ended September 30, 2010 primarily related to the Dominion Acquisition, as well as the equity and debt issuance that raised approximately $4.6 billion. Transaction and financing fees of $15 million incurred in the nine months ended September 30, 2011 related to the solicitation of consents of the long-term bonds needed in order to clarify the indentures that relate to joint arrangements with respect to its oil and gas properties.
- Bank fees increased $3 million in the period-to-period comparison due to the refinancing and extension of the previous $1.0 billion credit facility to $1.5 billion on May 7, 2010.
- Other corporate items increased $3 million due to various transactions that occurred throughout both periods, none of which were individually material.

Income Taxes:

The effective income tax rate was 20.6% for the nine months ended September 30, 2011 compared to 22.9% for the nine months ended September 30, 2010. The decrease in the effective tax rate for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010 was primarily attributable to various discrete transactions that occurred in both periods. The discrete transactions included an Internal Revenue Service audit settlement for 2006 and 2007 and the corresponding impacts to the 2010 accrued tax position which resulted in higher percentage depletion deductions. See Note 5—Income Taxes of the Notes to the Condensed Consolidated Financial Statements of this Form 10-Q for additional information.

	For the Nine Months Ended September 30,			
	2011	2010	Variance	Percent Change
Total Company Earnings Before Income Tax	$550	$329	$221	67.2%
Income Tax Expense	$113	$75	$38	50.7%
Effective Income Tax Rate	20.6%	22.9%	(2.3)%	

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Liquidity and Capital Resources

CONSOL Energy generally has satisfied its working capital requirements and funded its capital expenditures and debt service obligations with cash generated from operations and proceeds from borrowings. On April 12, 2011, CONSOL Energy amended and extended its $1.5 billion Senior Secured Credit Agreement through April 12, 2016. The previous facility was set to expire on May 7, 2014. The amendment provides more favorable pricing and the facility continues to be secured by substantially all of the assets of CONSOL Energy and certain of its subsidiaries. CONSOL Energy's credit facility allows for up to $1.5 billion for borrowings and letters of credit. CONSOL Energy can request an additional $250 million increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on a ratio of financial covenant debt to twelve-month trailing earnings before interest, taxes, depreciation, depletion and amortization (EBITDA), measured quarterly. The facility includes a minimum interest coverage ratio covenant of no less than 2.50 to 1.00, measured quarterly. The minimum interest coverage ratio covenant is calculated as the ratio of EBITDA to cash interest expense of CONSOL Energy and certain of its subsidiaries. The interest coverage ratio was 5.56 to 1.00 at September 30, 2011. The facility includes a maximum leverage ratio covenant of no more than 4.75 to 1.00 through March 2013, and no more than 4.50 to 1.00 thereafter, measured quarterly. The maximum leverage ratio covenant is calculated as the ratio of financial covenant debt to twelve-month trailing EBITDA for CONSOL Energy and certain subsidiaries. Financial covenant debt is comprised of the outstanding indebtedness and specific letters of credit, less cash on hand, of CONSOL Energy and certain of its subsidiaries. EBITDA, as used in the covenant calculation, excludes non-cash compensation expenses, non-recurring transaction expenses, uncommon gains and losses, gains and losses on discontinued operations and includes cash distributions received from affiliates plus pro-rata earnings from material acquisitions. The leverage ratio was 2.17 to 1.00 at September 30, 2011. The facility also includes a senior secured leverage ratio covenant of no more than 2.00 to 1.00, measured quarterly. The senior secured leverage ratio covenant is calculated as the ratio of secured debt to EBITDA. Secured debt is defined as the outstanding borrowings and letters of credit on the revolving credit facility. The senior secured leverage ratio was 0.19 to 1.00 at September 30, 2011. Covenants in the facility limit our ability to dispose of assets, make investments, purchase or redeem CONSOL Energy common stock, pay dividends, merge with another company and amend, modify or restate, in any material way, the senior unsecured notes. At September 30, 2011, the facility had no outstanding borrowings and $265,173 of letters of credit outstanding, leaving $1,234,827 of unused capacity. From time to time, CONSOL Energy is required to post financial assurances to satisfy contractual and other requirements generated in the normal course of business. Some of these assurances are posted to comply with federal, state or other government agencies statutes and regulations. We sometimes use letters of credit to satisfy these requirements and these letters of credit reduce our borrowing facility capacity.

CONSOL Energy also has an accounts receivable securitization facility. This facility allows the Company to receive, on a revolving basis, up to $200 million of short-term funding and letters of credit. The accounts receivable facility supports sales, on a continuous basis to financial institutions, of eligible trade accounts receivable. CONSOL Energy has agreed to continue servicing the sold receivables for the financial institutions for a fee based upon market rates for similar services. The cost of funds is based on commercial paper rates plus a charge for administrative services paid to financial institutions. At September 30, 2011, eligible accounts receivable totaled approximately $200 million and there were no outstanding borrowings or letters of credit outstanding against the facility.

On April 11, 2011, CONSOL Energy redeemed all of its outstanding $250 million, 7.875% Notes due March 1, 2012 in accordance with the terms of the indenture governing the Notes. 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 $268 million. CONSOL Energy's loss on extinguishment of debt was $16 million, which primarily represents the interest that would have been paid on these notes if held to maturity.

On April 12, 2011, CNX Gas entered into a $1.0 billion Senior Secured Credit Agreement which extends until April 12, 2016. It replaced the $700 million senior secured credit facility which was set to expire on May 6, 2014. The replacement facility provides more favorable pricing and the facility continues to be secured by substantially all of the assets of CNX Gas and its subsidiaries. CNX Gas' credit facility allows for up to $1.0 billion for borrowings and letters of credit. CNX Gas can request an additional $250 million increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. The facility includes a minimum interest coverage ratio covenant of no less than 3.00 to 1.00, measured quarterly. The minimum interest coverage ratio covenant is calculated as the ratio of EBITDA to cash interest expense for CNX Gas and its subsidiaries. The interest coverage ratio was 35.60 to 1.00 at September 30, 2011. The facility also includes a maximum leverage ratio covenant of no more than 3.50 to 1.00, measured quarterly. The maximum leverage ratio covenant is calculated as the ratio of financial covenant debt to twelve-month trailing EBITDA for CNX Gas and its subsidiaries. Financial covenant debt is comprised of the outstanding indebtedness and letters of credit, less cash on hand, of CNX Gas and its subsidiaries. EBITDA, as used in the covenant calculation, excludes non-cash compensation expenses, non-recurring transaction expenses, gains and losses on the sale of assets, uncommon gains and losses, gains and losses on discontinued operations and includes cash distributions received from affiliates plus pro-rata earnings from material acquisitions. The leverage ratio was 0.00 to 1.00 at September 30, 2011. Covenants in the facility limit our ability to dispose of assets, make investments, pay dividends and merge with another company. At September 30, 2011, the facility had no amounts drawn and $70,203 of letters of credit outstanding, leaving $929,797 of unused capacity.

Uncertainty in the financial markets brings additional potential risks to CONSOL Energy. The risks include declines in our stock price, less availability and higher costs of additional credit, potential counterparty defaults, and commercial bank failures. Financial market disruptions may impact our collection of trade receivables. As a result, CONSOL Energy constantly monitors the creditworthiness of our customers. We believe that our current group of customers are financially sound and represent no abnormal business risk.

CONSOL Energy believes that cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major acquisitions), scheduled debt payments, anticipated dividend payments and to provide required letters of credit. Nevertheless, the ability of CONSOL Energy to satisfy its working capital requirements, to service its debt obligations, to fund planned capital expenditures or to pay dividends will depend upon future operating performance, which will be affected by prevailing economic conditions in the coal and gas industries and other financial and business factors, some of which are beyond CONSOL Energy's control.

In order to manage the market risk exposure of volatile natural gas prices in the future, CONSOL Energy enters into various physical gas supply transactions with both gas marketers and end users for terms varying in length. CONSOL Energy has also entered into various gas swap transactions that qualify as financial cash flow hedges, which exist parallel to the underlying physical transactions. The fair value of these contracts was a net asset of $135 million at September 30, 2011. The ineffective portion of these contracts was insignificant to earnings in the three and nine months ended September 30, 2011. No issues related to our hedge agreements have been encountered to date.

CONSOL Energy frequently evaluates potential acquisitions. CONSOL Energy has funded acquisitions with cash generated from operations and a variety of other sources, depending on the size of the transaction, including debt and equity financing. There can be no assurance that additional capital resources, including debt and equity financing, will be available to CONSOL Energy on terms which CONSOL Energy finds acceptable, or at all.

Cash Flows (in millions)

	For the Nine Months Ended September 30,		
	2011	2010	Change
Cash flows from operating activities	$1,252	$879	$373
Cash used in investing activities	$(231)	$(5,255)	$5,024
Cash (used in) provided by financing activities	$(581)	$4,326	$(4,907)

Cash flows provided by operating activities changed in the period-to-period comparison primarily due to the following items:

- Operating cash flow increased $183 million in 2011 due to higher net income attributable to CONSOL Energy shareholders in the period-to-period comparison. The 2011 net income included an approximately $75 million reduction due to the abandonment of Mine 84 which is discussed further in Note 8—Property, Plant and Equipment, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q. This reduction did not have a corresponding reduction to cash flows from operating activities because it was primarily related to the write-down of assets remaining at Mine 84 at the time of the abandonment, not cash obligations.
- Operating cash flows increased $35 million in 2011 compared to the prior year due to differences in accrued income tax liabilities. The decrease in accrued income taxes in 2011 was $4 million compared to a decrease in accrued income taxes in the 2010 period of $39 million.

- Operating cash flows increased due to various other changes in operating assets, operating liabilities, other assets and other liabilities which occurred throughout both years, none of which were individually material.

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Net cash used in investing activities changed in the period-to-period comparison primarily due to the following items:

- On April 30, 2010, CONSOL Energy paid $3.474 billion for the Dominion Acquisition. See Note 2—Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional details.

- On May 28, 2010, CONSOL Energy paid $991 million to acquire the shares of CNX Gas common stock and vested stock options which it did not previously own.

- On September 30, 2011, CONSOL Energy received net proceeds of $519 million related to the Noble transaction. See Note 2—Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional details.

- On September 30, 2011, CONSOL Energy received a $67 million cash distribution from CONE Gathering LLC. See Note 2—Acquisitions and Dispositions, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional details.

- Total capital expenditures increased $176 million to $997 million in the nine months ended September 30, 2011 compared to $822 million in the nine months ended September 30, 2010. Capital expenditures for the gas segment increased $243 million due to the additional drilling in the period-to-period comparison. The increased gas segment capital was primarily due to the increased Marcellus Shale drilling. Capital expenditures for coal and other activities decreased $67 million in the period-to-period comparison. Face extension projects at various locations were lower by $83 million as a result of the majority of these projects being completed during the 2010 period, $13 million was incurred in the 2010 period as a result of a longwall shield lease buyout, and the 2011 period was lower by approximately $29 million related to the Buchanan Reverse Osmosis (RO) system which was primarily completed before January 1, 2011 and an approximate $18 million decrease in 2011 related to various other equipment expenditures throughout both periods. These reductions in coal and other capital were offset, in part by an approximate $61 million increase in expenditures related primarily to the ongoing development of the BMX Mine which is scheduled to go on-line in 2014, and a $15 million increase in 2011 related to the construction of the Northern West Virginia RO system.

Net cash (used in) provided by financing activities changed in the period-to-period comparison primarily due to the following items:

- Proceeds of $2.75 billion were received on April 1, 2010 in connection with the issuance of $1.5 billion of 8.00% senior unsecured notes due in 2017 and $1.25 billion of 8.25% senior unsecured notes due in 2020.
- In 2010, proceeds of $1.83 billion were received in connection with the issuance of 44.3 million shares of common stock which was completed on March 31, 2010.
- In 2011, CONSOL Energy repaid $200 million of borrowings under the accounts receivable securitization facility. In 2010, CONSOL Energy received proceeds of $150 million under this facility.
- In 2011, CONSOL Energy paid $266 million, including a make-whole provision, to redeem the 7.875% notes that were due in March 2012.
- In 2011, CONSOL Energy paid $15 million 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. See Note 10—Long-Term Debt, in the Notes to the Unaudited Consolidated Financial Statements included in this Form 10-Q for additional details.
- In 2011, CONSOL Energy paid outstanding borrowings of $155 million under the revolving credit facility. In 2010, CONSOL Energy paid $279 million under this facility.
- Dividends of $68 million were paid in 2011 compared to $63 million in 2010. The increase was due to the 44.3 million additional shares issued on March 31, 2010.

- In 2011, proceeds of $250 million were received in connection with the issuance of $250 million of 6.375% senior unsecured notes due in March 2021.
- In 2011, CNX Gas, a wholly-owned subsidiary, paid outstanding borrowings of $129 million under its revolving credit facility compared to receiving $20 million in 2010.

The following is a summary of our significant contractual obligations at September 30, 2011 (in thousands):

	Payments due by Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Purchase Order Firm Commitments	$174,979	$129,553	$7,094	$—	$311,626
Gas Firm Transportation	49,937	136,358	130,444	466,646	783,385
CONE Gathering Commitments	3,400	78,000	251,300	1,389,100	1,721,800
Long-Term Debt	11,718	6,517	5,173	3,111,744	3,135,152
Interest on Long-Term Debt	244,977	490,743	491,730	667,328	1,894,778
Capital (Finance) Lease Obligations	8,588	13,845	10,226	31,227	63,886
Interest on Capital (Finance) Lease Obligations	4,275	6,925	5,374	6,279	22,853
Operating Lease Obligations	89,379	143,291	102,069	130,724	465,463
Long-Term Liabilities—Employee Related (a)	230,132	484,762	521,037	2,444,423	3,680,354
Other Long-Term Liabilities (b)	393,548	137,498	73,573	410,486	1,015,105
Total Contractual Obligations (c)	$1,210,933	$1,627,492	$1,598,020	$8,657,957	$13,094,402

(a) Long-term liabilities—employee related include other post-employment benefits, work-related injuries and illnesses. Estimated salaried retirement contributions required to meet minimum funding standards under ERISA are excluded from the pay-out table due to the uncertainty regarding amounts to be contributed. Estimated 2011 contributions are expected to approximate $71.7 million.

(b) Other long-term liabilities include mine reclamation and closure and other long-term liability costs.

(c) The significant obligation table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

Debt

At September 30, 2011, CONSOL Energy had total long-term debt of $3.199 billion outstanding, including the current portion of long-term debt of $20 million. This long-term debt consisted of:

- An aggregate principal amount of $1.5 billion of 8.00% senior unsecured notes due in April 2017. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy’s subsidiaries.
- An aggregate principal amount of $1.25 billion of 8.25% senior unsecured notes due in April 2020. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy’s subsidiaries.
- An aggregate principal amount of $250 million of 6.375% notes due in March 2021. Interest on the notes is payable March 1 and September 1 of each year. Payment of the principal and interest on the notes are guaranteed by most of CONSOL Energy's subsidiaries.
- An aggregate principal amount of $103 million of industrial revenue bonds which were issued to finance the Baltimore port facility and bear interest at 5.75% per annum and mature in September 2025. Interest on the industrial revenue bonds is payable March 1 and September 1 of each year.
- $32 million in advance royalty commitments with an average interest rate of 7.56% per annum.
- An aggregate principal amount of $64 million of capital leases with a weighted average interest rate of 6.46% per annum.

At September 30, 2011, CONSOL Energy also had no outstanding borrowings and had approximately $265,173 of letters of credit outstanding under the $1.5 billion senior secured revolving credit facility.

At September 30, 2011, CONSOL Energy had no outstanding borrowings under the accounts receivable securitization facility.

At September 30, 2011, CNX Gas, a wholly owned subsidiary, had no outstanding borrowings and approximately $70,203 of letters of credit outstanding under its $1.0 billion secured revolving credit facility.
Total Equity and Dividends
CONSOL Energy had total equity of $3.4 billion at September 30, 2011 and $2.9 billion at December 31, 2010. Total equity increased primarily due to net income attributable to CONSOL Energy shareholders, proceeds received under the Patient Protection and Affordable Care Act, changes in the fair value of cash flow hedges and the amortization of stock-based compensation awards. Approximately $7.8 million of proceeds were received under the Patient Protection and Affordable Care Act related to reimbursements from the Federal government for retiree health spending which are reflected in Other Comprehensive Income. There is no guarantee that additional proceeds will be received under this program. These increases were offset, in part, by the declaration of dividends and the issuance of treasury stock. See the Consolidated Statements of Stockholders' Equity in Item 1 of this Form 10-Q for additional details.
Dividend information for the current year to date were as follows:

Declaration Date	Amount Per Share	Record Date	Payment Date
October 27, 2011	$0.125	November 11, 2011	November 25, 2011
July 29, 2011	$0.100	August 10, 2011	August 22, 2011
April 29, 2011	$0.100	May 13, 2011	May 24, 2011
January 28, 2011	$0.100	February 8, 2011	February 18, 2011

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 2.17 to 1.00 and our availability was approximately $1.2 billion at September 30, 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 nine months ended September 30, 2011.
Off-Balance Sheet Transactions
CONSOL Energy does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on CONSOL Energy’s financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the Notes to the Unaudited Consolidated Financial Statements. CONSOL Energy participates in various multi-employer benefit plans such as the United Mine Workers’ of America (UMWA) 1974 Pension Plan, the UMWA Combined Benefit Fund and the UMWA 1993 Benefit Plan which generally accepted accounting principles recognize on a pay as you go basis. These benefit arrangements may result in additional liabilities that are not recognized on the balance sheet at September 30, 2011. The various multi-employer benefit plans are discussed in Note 17—Other Employee Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of the December 31, 2010 Form 10-K. CONSOL Energy also uses a combination of surety bonds, corporate guarantees and letters of credit to secure our financial obligations for employee-related, environmental, performance and various other items which are not reflected on the balance sheet at September 30, 2011. Management believes these items will expire without being funded. See Note 11—Commitments and Contingencies in the Notes to the Unaudited Consolidated Financial Statements included in Item 1 of this Form 10-Q for additional details of the various financial guarantees that have been issued by CONSOL Energy.

Recent Accounting Pronouncements

In September 2011, the Financial Accounting Standards Board issued an update to the Compensation-Retirement Benefits-Multiemployer Plans Subtopic 715-80 of the Accounting Standards Codification which is intended to provide financial statement users with more information to assess the potential future cash flow implications relating to an employer's participation in multiemployer pension plans. The required additional disclosures will also indicate the financial health of all of the significant plans in which the employer participates and assist a financial statement user to access additional information that is available outside the financial statements. The effective date of this update is December 15, 2011 with early adoption permitted. We believe adoption of this new guidance will not have a material impact on CONSOL Energy's financial statements as this update has an impact on presentation only.

In June 2011, the Financial Accounting Standards Board issued an update to the Comprehensive Income Topic of the Accounting Standards Codification intended to improve the comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. This update eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity, requires consecutive presentation of the statement of net income and other comprehensive income, and requires an entity to present reclassification adjustments on the face of the financial statements from other comprehensive income (OCI) to net income. The effective date of this update is December 15, 2011 with early adoption permitted. We believe adoption of this new guidance will not have a material impact on CONSOL's financial statements as these updates have an impact on presentation only.

Forward-Looking Statements

We are including the following cautionary statement in this Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q speak only as of the date of this Quarterly Report on Form 10-Q; 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 economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets cause conditions we cannot predict;
- an extended decline in prices we receive for our coal and 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 gas to market;

- a loss of our competitive position because of the competitive nature of the coal and 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, as well as the impact of any adopted regulations on our coal mining operations due to the venting of coalbed methane which occurs during mining;
- foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;
- the risks inherent in coal and 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;
- our focus on new gas development projects and exploration for gas in areas where we have little or no proven gas reserves;
- decreases in the availability of, or increases in, the price of commodities and services used in our mining and gas operations, as well as our exposure under "take or pay" contracts we entered into with well service providers to obtain services which if not used could impact our cost of production;
- 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 gas operations;
- the effects of stringent federal and state employee health and safety regulations, including the ability of regulators to shut down a mine or 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 outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;
- the impacts of various asbestos litigation claims;
- increased exposure to employee related long-term liabilities;
- increased 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 and joint ventures that we recently have completed or entered into or may make in the future including the accuracy of our assessment of the acquired businesses and their risks, achieving any anticipated synergies or other benefits (including joint venture partners paying carry obligations), 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 anti-takeover effects of our rights plan could prevent a change of control;
- increased exposure on our financial performance due to the degree we are leveraged;
- replacing our natural gas reserves, which if not replaced, will cause our gas reserves and gas production to decline;
- our ability to acquire water supplies needed for 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;

- our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- other factors discussed in our 2010 Form 10-K under “Risk Factors,” as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In addition to the risks inherent in operations, CONSOL Energy is exposed to financial, market, political and economic risks. The following discussion provides additional detail regarding CONSOL Energy's exposure to the risks of changing commodity prices, interest rates and foreign exchange rates.

CONSOL Energy is exposed to market price risk in the normal course of selling natural gas production and to a lesser extent in the sale of coal. CONSOL Energy sells coal under both short-term and long-term contracts with fixed price and/or indexed price contracts that reflect market value. CONSOL Energy uses fixed-price contracts, collar-price contracts and derivative commodity instruments that qualify as cash-flow hedges under the Derivatives and Hedging Topic of the Financial Accounting Standards Board Accounting Standards Codification to minimize exposure to market price volatility in the sale of natural gas. Our risk management policy prohibits the use of derivatives for speculative purposes.

CONSOL Energy has established risk management policies and procedures to strengthen the internal control environment of the marketing of commodities produced from its asset base. All of the derivative instruments without other risk assessment procedures are held for purposes other than trading. They are used primarily to mitigate uncertainty, volatility and cover underlying exposures. CONSOL Energy's market risk strategy incorporates fundamental risk management tools to assess market price risk and establish a framework in which management can maintain a portfolio of transactions within pre-defined risk parameters.

CONSOL Energy believes that the use of derivative instruments, along with our risk assessment procedures and internal controls, mitigates our exposure to material risks. However, the use of derivative instruments without other risk assessment procedures could materially affect CONSOL Energy's results of operations depending on market prices. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity.

For a summary of accounting policies related to derivative instruments, see Note 1—Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of CONSOL Energy's 2010 Form 10-K.

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at September 30, 2011. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $48.5 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $48.5 million.

CONSOL Energy’s interest expense is sensitive to changes in the general level of interest rates in the United States. At September 30, 2011, CONSOL Energy had $3,199 million aggregate principal amount of debt outstanding under fixed-rate instruments and no debt outstanding under variable-rate instruments. CONSOL Energy’s primary exposure to market risk for changes in interest rates relates to our revolving credit facility, under which there were no borrowings outstanding at September 30, 2011. CONSOL Energy’s revolving credit facility bore interest at a weighted average rate of 4.07% per annum during the nine months ended September 30, 2011. A 100 basis-point increase in the average rate for CONSOL Energy’s revolving credit facility would not have significantly decreased net income for the period. CNX Gas, also had borrowings during the period under its revolving credit facility which bears interest at a variable rate. CNX Gas’ facility had no outstanding borrowings at September 30, 2011 and bore interest at a weighted average rate of 2.08% per annum during the nine months ended September 30, 2011. Due to the level of borrowings against this facility and the low weighted average interest rate in the nine months ended September 30, 2011, a 100 basis-point increase in the average rate for CNX Gas’ revolving credit facility would not have significantly decreased net income for the period.

Almost all of CONSOL Energy’s transactions are denominated in U.S. dollars, and, as a result, it does not have material exposure to currency exchange-rate risks.

Hedging Volumes

As of October 24, 2011 our hedged volumes for the periods indicated are as follows:

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2011 Fixed Price Volumes					
Hedged Mcf	13,035,790	23,069,925	23,948,795	23,948,795	84,003,305
Weighted Average Hedge Price/Mcf	$5.56	$5.14	$5.12	$5.18	$5.21
2012 Fixed Price Volumes					
Hedged Mcf	19,108,632	19,108,632	19,318,617	19,318,617	76,854,498
Weighted Average Hedge Price/Mcf	$5.25	$5.25	$5.25	$5.25	$5.25
2013 Fixed Price Volumes					
Hedged Mcf	11,585,912	11,714,644	11,843,376	11,843,376	46,987,308
Weighted Average Hedge Price/Mcf	$5.19	$5.19	$5.19	$5.19	$5.19
2014 Fixed Price Volumes					
Hedged Mcf	9,921,990	10,032,234	10,142,478	10,142,478	40,239,180
Weighted Average Hedge Price/Mcf	$5.34	$5.34	$5.34	$5.34	$5.34

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures. CONSOL Energy, under the supervision and with the participation of its management, including CONSOL Energy’s principal executive officer and principal financial officer, evaluated the effectiveness of the Company’s “disclosure controls and procedures,” as such term is defined in Rule 13a-15(e) under the Securities Act of 1934, as amended (the “Exchange Act”), as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on that evaluation, CONSOL Energy’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures are effective as of September 30, 2011 to ensure that information required to be disclosed by CONSOL Energy in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by CONSOL Energy in such reports is accumulated and communicated to CONSOL Energy’s management, including CONSOL Energy’s principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal controls over financial reporting. There were no changes in the Company's internal controls over financial reporting that occurred during the fiscal quarter covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS
The first through the twenty-fourth paragraphs of Note 11—Commitments and Contingencies in the Notes to the Unaudited Consolidated Financial Statements included in Item 1 of this Form 10-Q are incorporated herein by reference.

ITEM 1A. RISK FACTORS
The following risk factors are updated from our annual report on Form 10-K for the year ended December 31, 2010.
Our coal mining and 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 wells for coalbed methane (CBM) or other gas 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;
- surface spillage of, or contamination of groundwater by, fracturing fluids used in hydraulic fracturing operations; 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.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, health and safety matters and others that govern our business have increased our costs of doing business for both coal and 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 and health and safety matters. 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, 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, control 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 and health and safety 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 and health and safety 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 and corresponding state laws (including those relating to protection of "impaired waters" (not meeting state water quality standards) through the use of effluent limitations established so that all discharges to the "impaired" stream do not exceed Total Maximum Daily Load ("TMDL") levels of the pollutants causing the impairment; anti-degradation regulations which protect state designated "high quality/exceptional use" streams by restricting or prohibiting "discharges" which result in degradation; and requirements to treat discharges from coal mining properties for non-traditional pollutants requiring expensive treatment technologies, such as total dissolved solids, chlorides and selenium; and "protecting" streams, wetlands, other regulated water sources and associated riparian lands from the surface impacts of underground mining) 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. Also, beginning in early 2009, the EPA has relied upon the Clean Water Act to become more actively involved in the permitting of mountain top removal mining operations and other coal mining operations requiring permits to place fill material in streams. 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. 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. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy ("DOE"), the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior is also considering regulation of hydraulic fracturing activities on public lands. 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. For example, on June 17, 2011, Texas enacted a law that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production) and the public. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, 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 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. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we ultimately are able to produce in commercially paying quantities from our gas properties.

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.

Some of the gas rights we believe we control are in areas where we have not yet done any exploratory or production drilling. Many of these properties were acquired primarily for the coal rights, and, in many cases were acquired years ago. While chain of title work for the coal estate was generally established, in some cases, the gas estate title work is less developed. Our practice is to perform a thorough title examination of the gas estate before we commence drilling activities and 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.

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 engage in divestitures or joint ventures, we do not control the timing of these and they may not provide anticipated benefits.

On April 30, 2010 we completed the Dominion Acquisition for approximately $3.5 billion. We could encounter difficulties with the Dominion Acquisition, such as the need to revisit assumptions about gas reserves, future gas production, revenues, capital expenditures and operating costs, including realizing anticipated synergies, the loss of key employees or commercial relationships or the need to address unanticipated liabilities. If we cannot successfully integrate our business, we may fail to realize the expected benefits of the acquisition. 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, our profitability may decline and we could experience an adverse effect on our business, financial condition, or results of operations. Mine expansion, gas operation expansion and acquisition transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental 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;
- 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 of 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 these to be subject to future matters that we do not control. For example, we sold a 50% undivided interest in certain Marcellus shale acreage to Noble Energy Corporation and entered into a joint development agreement with it regarding the development of this acreage. Of the approximately $3.3 billion we anticipate receiving, approximately $2.1 billion depends upon Noble Energy paying during a specified period of time a portion of our share of drilling and development costs for new wells, which we call “carried costs”. In addition, Noble Energy's obligation to pay carried costs is suspended if average 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. We entered into a similar transaction with Hess Corporation in which approximately $534 million of the total anticipated consideration of $593 million is dependent upon Hess paying carried costs. If for any reason the number of new wells drilled during the relevant term under one of these arrangements is significantly less than we anticipate, or the obligation to pay carried costs is suspended for a significant period of time in the case of the Noble Energy arrangement, the amount of carried costs paid by the other party would be less than we anticipate and we would not realize the expected economic benefit from these arrangements.

ITEM 5. OTHER INFORMATION

Mine Safety and Health Administration Safety Data

We believe that CONSOL Energy is one of the safest mining companies in the world. The Company has in place health and safety programs that include extensive employee training, accident prevention, workplace inspection, emergency response, accident investigation, regulatory compliance and program auditing. The objectives of our health and safety programs are to eliminate workplace incidents, comply with all mining-related regulations and provide support for both regulators and the industry to improve mine safety.

The operation of our mines is subject to regulation by the federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Act). MSHA inspects our mines on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. We present information below regarding certain mining safety and health citations which MSHA has issued with respect to our coal mining operations. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed.

During the three months ended September 30, 2011, neither CONSOL Energy’s mining complexes nor its closed and/or idled mines: (i) were assessed any Mine Act section 110(b)(2) penalties for failure to correct the subject matter of a Mine Act section 104(a) citation within the specified time period, which failure was deemed flagrant (i.e., a reckless or repeated failure to make reasonable efforts to eliminate a known violation that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury) or (ii) received any MSHA written notices under Mine Act section 104(e) of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern. There was one Mine Act section 107(a) imminent danger orders to immediately remove miners. There was one pending legal action before the Federal Mine Safety and Health Review Commission (excluding actions pending before Administrative Law Judges). There were no fatalities during the three months ended September 30, 2011.

During the nine months ended September 30, 2011, neither CONSOL Energy’s mining complexes nor its closed and/or idled mines: (i) were assessed any Mine Act section 110(b)(2) penalties for failure to correct the subject matter of a Mine Act section 104(a) citation within the specified time period, which failure was deemed flagrant (i.e., a reckless or repeated failure to make reasonable efforts to eliminate a known violation that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury) or (ii) received any MSHA written notices under Mine Act section 104(e) of a pattern of violation of mandatory health or safety standards or of the potential to have such a pattern. There were two Mine Act section 107(a) imminent danger orders to immediately remove miners. There was one pending legal action before the Federal Mine Safety and Health Review Commission (excluding actions pending before Administrative Law Judges). There were no fatalities during the nine months ended September 30, 2011.

The table below sets forth by mining complex the total number of citations and/or orders issued by MSHA to CONSOL Energy and its subsidiaries under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments, received during the three months ended September 30, 2011 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for each of our mining complexes.

Name of Mine or Mining Complex(1)(2)	Mine Act Section 104 Significant & Substantial Citations(3)	Mine Act Section 104(b) Orders(4)	Mine Act Section 104(d) Citations & Orders(5)	Total Dollar Value of Proposed MSHA Assessments(6) (in thousands)	Number of Legal Actions Pending Before the Federal Mine Safety and Health Review Commission(7)
Amvest - Fola Complex	19	—	—	$20	16
Bailey	8	—	—	$28	9
Blacksville #2	56	—	1	$226	11
Buchanan	47	—	—	$720	23
Enlow Fork	9	—	—	$33	5
Loveridge	77	2	2	$459	7
McElroy	83	—	4	$436	16
Miller Creek Complex	34	—	—	$30	4
Robinson Run	26	—	—	$175	15
Shoemaker	72	—	—	$172	9
Other (Keystone Plant)	—	—	—	$—	—

(1) MSHA assigns an identification number to each coal mine and may or may not assign separate identification numbers to related facilities such as preparation plants. We are providing the information in the table by mining complex rather than MSHA identification number because that is how we manage and operate our coal mining business.

(2) We have not included currently closed or idled mines in the above table. Our closed and/or idled mines received one Mine Act section 104 Significant & Substantial citations in the three months ended September 30, 2011. Total proposed assessments were $102 in the three months ending September 30, 2011. There were 13 legal actions in total pending before the Federal Mine Safety and Health Review Commission as of September 30, 2011 for our closed and/or idle mines. These actions may have been initiated in prior quarters.

(3) Mine Act section 104(a) significant and substantial citations are for alleged violations of a mining safety standard or regulation where there exists a reasonable likelihood that the hazard contributed to or will result in an injury or illness of a reasonably serious nature.

(4) Mine Act section 104(b) orders are for alleged failure to totally abate the subject matter of a Mine Act section 104(a) citation within the period specified in the citation.

(5) Mine Act section 104(d) citations and orders are for an alleged unwarrantable failure (i.e. aggravated conduct constituting more than ordinary negligence) to comply with a mining safety standard or regulation.

(6) Includes proposed MSHA assessments received during the three months ended September 30, 2011 for all alleged violations. MSHA assessments are not necessarily made in the same period as the citation occurs.

(7) Includes all legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for each of our mining complexes. These actions may have been initiated in prior quarters. All of the legal actions were initiated by us to contest citations, orders, or proposed assessments issued by MSHA, and if we are successful, may result in the reduction or dismissal of those citations, orders or assessments.

The table below sets forth by mining complex the total number of citations and/or orders issued by MSHA to CONSOL Energy and its subsidiaries under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments, received during the nine months ended September 30, 2011 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for each of our mining complexes.

Name of Mine or Mining Complex(1)(2)	Mine Act Section 104 Significant & Substantial Citations(3)	Mine Act Section 104(b) Orders(4)	Mine Act Section 104(d) Citations & Orders(5)	Total Dollar Value of Proposed MSHA Assessments(6) (in thousands)	Number of Legal Actions Pending Before the Federal Mine Safety and Health Review Commission(7)
Amvest - Fola Complex	50	—	1	$83	16
Bailey	34	—	—	$216	9
Blacksville #2	155	—	4	$705	11
Buchanan	118	—	—	$1,029	23
Enlow Fork	32	—	—	$59	5
Loveridge	220	3	10	$1,007	7
McElroy	232	—	7	$871	16
Miller Creek Complex	88	—	—	$72	4
Robinson Run	110	—	2	$778	15
Shoemaker	178	—	2	$517	9
Other (Keystone Plant)	1	—	—	$5	—

(1) MSHA assigns an identification number to each coal mine and may or may not assign separate identification numbers to related facilities such as preparation plants. We are providing the information in the table by mining complex rather than MSHA identification number because that is how we manage and operate our coal mining business.

(2) We have not included currently closed or idled mines in the above table. Our closed and/or idled mines received six Mine Act section 104 Significant & Substantial citations in the nine months ended September 30, 2011. Total proposed assessments were $136 in the nine months ending September 30, 2011. There were 13 legal actions in total pending before the Federal Mine Safety and Health Review Commission as of September 30, 2011 for our closed and/or idle mines. These actions may have been initiated in prior quarters.

(3) Mine Act section 104(a) significant and substantial citations are for alleged violations of a mining safety standard or regulation where there exists a reasonable likelihood that the hazard contributed to or will result in an injury or illness of a reasonably serious nature.

(4) Mine Act section 104(b) orders are for alleged failure to totally abate the subject matter of a Mine Act section 104(a) citation within the period specified in the citation.

(5) Mine Act section 104(d) citations and orders are for an alleged unwarrantable failure (i.e. aggravated conduct constituting more than ordinary negligence) to comply with a mining safety standard or regulation.

(6) Includes proposed MSHA assessments received during the nine months ended September 30, 2011 for all alleged violations. MSHA assessments are not necessarily made in the same period as the citation occurs.

(7) Includes all legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for each of our mining complexes. These actions may have been initiated in prior quarters. All of the legal actions were initiated by us to contest citations, orders, or proposed assessments issued by MSHA, and if we are successful, may result in the reduction or dismissal of those citations, orders or assessments.

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ITEM 6. EXHIBITS

2.1	Asset Acquisition Agreement dated August 17, 2011 between CNX Gas Company LLC and Noble Energy, Inc. (including Annex I (Definitions) thereto), incorporated by reference to Exhibit 2.1 to Form 8-K filed on August 18, 2011. Schedules and Exhibits to the Asset Acquisition Agreement identified in the Table of Contents to the Asset Acquisition Agreement are not being filed but will be furnished supplementally to the Securities and Exchange Commission upon request.
2.2	Joint Development Agreement by and among CNX Gas Company LLC and Noble Energy, Inc. dated as of September 30, 2011. Schedules and Exhibits to the Joint Development Agreement identified in the Table of Contents to the Joint Development Agreement are not being filed but will be furnished supplementally to the Securities and Exchange Commission upon request.
4.1	Supplemental Indenture No. 3 dated as of August 24, 2011 to Indenture dated as of April 1, 2010 among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 8.00% Senior Notes due 2017, incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 29, 2011.*
4.2	Supplemental Indenture No. 3 dated as of August 24, 2011 to Indenture dated as of April 1, 2010 among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 8.250% Senior Notes due 2020, incorporated by reference to Exhibit 4.2 to Form 8-K filed on August 29, 2011.
4.3	Supplemental Indenture No. 1 dated as of August 24, 2011 to Indenture dated as of March 9, 2011 among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 6.375% Senior Notes due 2021, incorporated by reference to Exhibit 4.3 to Form 8-K filed on August 29, 2011.
10.2	Closing Agreement by and between CNX Gas Company LLC and Noble Energy, Inc. dated as of September 30, 2011.
10.3	Amendment to CONSOL Energy Inc. Supplemental Retirement Plan dated October 17, 2011.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	Interactive Data File (Form 10-Q for the quarterly period ended September 30, 2011 furnished in XBRL)

In accordance with SEC Release 33-8238, Exhibits 32.1 and 32.2 are being furnished and not filed.

* The Asset Acquisition Agreement and Joint Development Agreement are not intended to be sources of financial, business or operational information about CONSOL Energy or any of its subsidiaries or affiliates or their assets. The representations, warranties and covenants contained in the these agreements are made solely for purposes of the respective agreement and are made as of their respective date; are solely for the benefit of the parties; may be subject to qualifications and limitations agreed upon by the parties in connection with negotiating the terms of these agreements, including being made for the purpose of allocating contractual risk between the parties instead of establishing matters as facts; and may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors or security holders. Investors and security holders should not rely on the representations, warranties and covenants or any description thereof as characterizations of the actual state of facts or condition of CONSOL Energy or any of its subsidiaries or affiliates or their assets. Moreover, information concerning the subject matter of the representations, warranties and covenants may change after the date of these agreements, which subsequent information may or may not be fully reflected in public disclosures.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Dated: October 31, 2011

CONSOL ENERGY INC.

By: /S/ J. BRETT HARVEY
J. Brett Harvey
Chairman of the Board and Chief Executive Officer
(Duly Authorized Officer and Principal Executive Officer)

By: /S/ WILLIAM J. LYONS
William J. Lyons
Chief Financial Officer and Executive Vice President
(Duly Authorized Officer and Principal Financial and Accounting Officer)