SPIRIT FINANCE CORP
Form 10-Q
May 10, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

ý	**QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2005

o	**TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 01-32386

SPIRIT FINANCE CORPORATION

(Exact name of registrant as specified in its charter)

Maryland (State or other jurisdiction of incorporation or organization)	**20-0175773** (I.R.S. Employer Identification No.)
14631 N. Scottsdale Road, Suite 200 **Scottsdale, Arizona** (Address of principal executive offices)	**85254** (Zip Code)

Registrant's telephone number, including area code: **(480) 606-0820**

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 past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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

As of April 30, 2005, 67,626,643 shares of the registrant's Common Stock, par value $0.01 per share, were outstanding.

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

Spirit Finance Corporation

CONSOLIDATED BALANCE SHEETS

	March 31, 2005	December 31, 2004
	(Unaudited)	
Assets		
Investments, at cost:		
Real estate investments:		
Land and improvements	$ 265,946,425	$ 257,233,314
Buildings and improvements	379,122,916	358,810,789
Total real estate investments	645,069,341	616,044,103
Less: Accumulated depreciation	(7,380,642)	(4,302,892)
	637,688,699	611,741,211
Mortgage loans receivable	40,733,973	40,854,680
Net investments	678,422,672	652,595,891
Cash and cash equivalents	42,791,176	113,224,972
Intangible assets	11,313,312	10,742,090
Deferred costs and other assets	6,467,183	5,664,271
Total assets	$ 738,994,343	$ 782,227,224
Liabilities and stockholders' equity		
Liabilities:		
Mortgages and notes payable	$ 38,456,210	$ 178,854,127
Secured credit facilities	58,656,965	
Dividends payable	12,849,062	7,109,774
Accounts payable, accrued expenses and other liabilities	5,250,929	8,559,851
Total liabilities	115,213,166	194,523,752
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Preferred stock, $0.01 par value per share, 125,000,000 shares authorized, no shares issued and outstanding		
Common stock, $0.01 par value per share, 375,000,000 shares authorized, 67,626,643 (March 31, 2005) and 63,506,819 (December 31, 2004) shares issued and outstanding	676,266	635,068
Capital in excess of par value	639,531,032	599,300,330
Accumulated distributions in excess of net income	(14,680,375)	(8,649,997)
Accumulated other comprehensive loss	(1,745,746)	(3,581,929)
Total stockholders' equity	623,781,177	587,703,472
Total liabilities and stockholders' equity	$ 738,994,343	$ 782,227,224

	March 31, 2005	December 31, 2004

See accompanying notes.

Spirit Finance Corporation

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended March 31	
	2005	**2004**
Revenues:		
Rentals	$ 14,339,271	$ 977,788
Interest income on mortgage loans receivable	930,231	936,441
Other interest income	355,389	639,049
Total revenues	15,624,891	2,553,278
Expenses:		
General and administrative	2,651,084	1,467,387
Depreciation and amortization	3,388,423	273,860
Interest	2,766,700	
Total expenses	8,806,207	1,741,247
Net income	$ 6,818,684	$ 812,031
Net income per common share:		
Basic	$ 0.10	$ 0.02
Diluted	$ 0.10	$ 0.02
Weighted average outstanding common shares:		
Basic	67,023,019	35,538,326
Diluted	67,443,662	35,668,996

See accompanying notes.

Spirit Finance Corporation

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31	
	2005	2004
Cash flows from operating activities		
Net income	$ 6,818,684	$ 812,031
Adjustments to net income:		
Depreciation and amortization	3,388,423	273,860
Stock-based compensation	202,887	228,351
Amortization of deferred financing costs	579,609	
Other noncash items	109,615	15,851
Changes in operating assets and liabilities:		
Deferred costs and other assets	(760,850)	(328,296)
Accounts payable, accrued expenses and other liabilities	(1,468,353)	61,503
Net cash provided by operating activities	8,870,015	1,063,300
Cash flows from investing activities		
Acquisitions of real estate investments	(38,041,696)	(10,948,633)
Proceeds from sales of real estate investments	8,100,809	
Collections of principal on mortgage loans receivable	105,422	72,848
Net cash used by investing activities	(29,835,465)	(10,875,785)
Cash flows from financing activities		
Borrowings under secured credit facilities	101,499,562	
Repayments under secured credit facilities	(42,842,597)	
Repayments of mortgages and notes payable	(140,266,423)	
Deferred financing costs	(489,436)	
Proceeds from initial public offering, net	40,066,945	
Proceeds from private offering, net		55,699,768
Dividends paid on common stock	(7,109,774)	
Transfers to restricted cash and escrow deposits	(326,623)	(150,000)
Net cash (used) provided by financing activities	(49,468,346)	55,549,768
Net (decrease) increase in cash and cash equivalents	(70,433,796)	45,737,283
Cash and cash equivalents, beginning of period	113,224,972	199,088,674
Cash and cash equivalents, end of period	$ 42,791,176	$ 244,825,957

See accompanying notes.

Spirit Finance Corporation

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

Three Months Ended March 31, 2005

(Unaudited)

	Common Shares	Common Stock Par Value	Capital in Excess of Par Value	Accumulated Distributions in Excess of Net Income	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
Balances at December 31, 2004	63,506,819	$ 635,068	$ 599,300,330	$ (8,649,997)	$ (3,581,929)	$ 587,703,472
Net income				6,818,684		6,818,684
Net unrealized gain on cash flow hedges					1,836,183	1,836,183
Underwriters' over-allotment on initial public offering, net	3,913,043	39,130	40,027,815			40,066,945
Dividends declared on common stock ($0.19 per share)				(12,849,062)		(12,849,062)
Restricted stock grants, net	206,781	2,068				2,068
Stock-based compensation			202,887			202,887
Balances at March 31, 2005	67,626,643	$ 676,266	$ 639,531,032	$ (14,680,375)	$ (1,745,746)	$ 623,781,177

See accompanying notes.

Spirit Finance Corporation

Notes to Consolidated Financial Statements

(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Spirit Finance Corporation ("Spirit Finance" or the "Company") is a Maryland corporation formed on August 14, 2003 as a self-managed and self-advised real estate investment trust ("REIT") under the Internal Revenue Code. The common stock of Spirit Finance is listed on the New York Stock Exchange under the symbol "SFC."

Basis of Accounting and Principles of Consolidation

The accompanying unaudited consolidated financial statements are prepared on the accrual basis of accounting in accordance with U.S. generally accepted accounting principles for interim financial information. Accordingly, they do not include all of the information and footnotes required for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been recorded. Operating results for the three months ended March 31, 2005 are not necessarily indicative of the results that may be expected for the year ending December 31, 2005. The accompanying financial statements and notes should be read in conjunction with the audited financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2004.

The consolidated financial statements of Spirit Finance include the accounts of the Company and its wholly owned subsidiaries, Spirit Management Company ("Spirit Management"), Spirit Finance Acquisitions, LLC ("Spirit Acquisitions") and several wholly owned special purpose entities. The assets of the special purpose entities are not available to pay, or otherwise satisfy obligations to, the creditors of any owner or affiliate of the special purpose entities. Assets totaling $359,518,000 at March 31, 2005 and $331,447,000 at December 31, 2004 and liabilities totaling $96,007,000 at March 31, 2005 and $178,064,000 at December 31, 2004 were held by special purpose entities and are included in the accompanying respective Consolidated Balance Sheets. All intercompany account balances and transactions have been eliminated in consolidation.

For a complete listing of the Company's significant accounting policies, please refer to Note 2 in the Company's Annual Report on Form 10-K for the year ended December 31, 2004.

Reclassifications

Certain reclassifications have been made to prior period balances to conform to the current period presentation.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes its estimates are reasonable, actual results could differ from those estimates.

New Accounting Standard

In December 2004, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123R").

This standard requires companies to recognize compensation expense using a fair-value based method for all equity-classified awards granted, modified or settled for periods beginning after June 15, 2005. On April 14, 2005, the Securities and Exchange Commission delayed the effective date of SFAS No. 123R to January 1, 2006 for calendar-year public companies. The Company will continue to evaluate the use of "path-dependent" valuation models to value certain stock-based awards containing "market conditions" under SFAS No. 123R. Adoption of SFAS No. 123R in the first quarter of 2006 is not expected to have a material effect on the Company's financial position or results of operations.

2. INVESTMENTS

At March 31, 2005, Spirit Finance owned 313 real estate properties with a gross acquisition cost of $656,868,853 and financed 67 properties through mortgage loans receivable with a carrying value of $40,733,973. During the first three months of 2005, the Company had the following property transactions:

	Number of Properties Owned or Financed	Dollar Amount of Real Estate Investments(a)
Balance, December 31, 2004	374	$ 667,926,549
Acquisitions	12	38,041,696
Sales	(6)	(8,244,712)
Principal payments and premium amortization		(120,707)
Balance, March 31, 2005	380	$ 697,602,826

(a) The dollar amount of real estate investments includes the gross cost of land, buildings and related lease intangibles and the carrying amount of the mortgage loans receivable.

The acquisitions made in the first three months of 2005 included $1,202,000 allocated to the value of related lease intangibles. As of March 31, 2005, the Company's total real estate investments consisted of the following property types:

Property Type	Number of Properties Owned or Financed	Percentage of Dollar Amount of Real Estate Investments
Restaurants	239	39%
Movie theaters	11	17%
Specialty retailer properties	20	13%
Educational facilities	8	9%
Distribution facilities	51	8%
Drugstores	14	6%
Interstate travel plazas	4	5%
Automotive parts and service facilities	33	3%
Total	380	100%

The Company's real estate investments are geographically dispersed throughout 38 states. Only three states, Texas (11.1%), Arizona (10.5%) and Georgia (10.0%), accounted for 10% or more of the total gross investment of Spirit Finance's real estate portfolio at March 31, 2005. A majority of the Company's real estate investments are pledged as collateral under debt obligations (see Note 4).

The Company's 313 real estate properties are leased to customers under long-term operating leases that typically include one or more renewal options. The weighted average remaining

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noncancelable lease term at March 31, 2005 is approximately 15 years. The leases are generally triple-net, which provides that the lessee is responsible for the payment of all property operating expenses, including property taxes, maintenance and insurance; therefore, Spirit Finance is not responsible for repairs or other capital expenditures related to the properties.

No loan loss allowances were recorded on the mortgage loans receivable at March 31, 2005 or December 31, 2004.

3. INTANGIBLE ASSETS

Intangible assets represent the value of in-place leases and above-market rents. Total intangible assets are shown in the accompanying Consolidated Balance Sheets net of accumulated amortization of $486,000 at March 31, 2005 and $286,000 at December 31, 2004.

4. DEBT

In the first quarter of 2005, Spirit Finance repaid the entire $140,135,181 balance of its secured variable-rate mortgage notes payable that was outstanding at December 31, 2004. The remaining fixed-rate mortgages and notes payable have a carrying amount of $38,456,210 at March 31, 2005 compared to $38,718,946 at December 31, 2004. The fixed-rate mortgages are collateralized by underlying real estate with an aggregate net book value of $52,141,000.

In addition to the Company's existing $250,000,000 secured credit facility with Bank of America Mortgage Capital Corporation, in March 2005 Spirit Finance established a $125,000,000 secured credit facility with Citigroup Global Markets Realty Corporation. This facility represents short-term financing pending the issuance of debt under a long-term structured finance transaction. The facility matures in June 2005 but may be extended to September 2005 at the request of the Company. Borrowings under the facility require monthly payments of interest indexed to LIBOR, plus 1.75%. In addition, the Company pays an annualized fee of 0.25% on the unborrowed balance under the facility.

There was $58,656,965 outstanding under the secured credit facilities at March 31, 2005. No amounts were outstanding at December 31, 2004. Subsequent to March 31, 2005, the Company borrowed an additional $32,273,000 under the secured credit facilities. As of March 31, 2005, assets with an aggregate net book value of $425,177,000 (including all of the Company's mortgage notes receivable) were pledged as collateral for borrowings under the facilities.

Financing costs related to establishing the Company's debt, totaling $2,398,000 at March 31, 2005 and $2,488,000 at December 31, 2004 (net of amortization), are deferred and amortized to interest expense over the initial term of the related debt and are included in the caption, "Deferred costs and other assets."

The mortgage notes payable contain various covenants customarily found in mortgage notes, including a limitation on the Company's ability to incur additional indebtedness on the underlying real estate. The Company is also subject to various financial and nonfinancial covenants under the secured credit facilities, including debt service coverage and total debt to total gross assets ratios, and a minimum liquidity requirement of $25,000,000. As of March 31, 2005, Spirit Finance was in compliance with these covenants.

5. DERIVATIVE FINANCIAL INSTRUMENTS

In addition to the Company's existing forward-starting interest rate swap agreement with a notional amount of $235,000,000, on March 31, 2005, Spirit Finance entered into a forward-starting interest rate swap agreement with a notional amount of $87,000,000. The derivative instruments were designated to hedge the variability of cash flows related to forecasted interest payments over a weighted average life of 15 years on long-term debt expected to be issued in 2005. As the hedging relationships are expected to be highly effective at achieving offsetting changes in cash flows, these interest rate swaps are accounted for as cash flow hedges. The fair value of the interest rate swaps resulted in an unrealized loss of $1,745,746 at March 31, 2005 and $3,581,929 at December 31, 2004. These amounts are included in "Accounts payable, accrued expenses and other liabilities" with the corresponding amounts recorded in "Accumulated other comprehensive loss." No hedge ineffectiveness was recognized during the first quarter of 2005 and the hedges continue to be effective.

6. STOCKHOLDERS' EQUITY

On January 7, 2005, the Company issued 3,913,043 shares of common stock for proceeds of $40,066,945, net of underwriters' discount and offering expenses, as a result of the exercise of the underwriters' over-allotment option related to the Company's initial public offering. During the first quarter of 2005, the Company granted 206,781 shares (net of forfeitures) of restricted stock to officers and employees.

During the first quarter of 2005, the Company declared dividends of $0.19 per common share to shareholders of record as of April 15, 2005. The dividend, which totaled $12,849,062, was paid on April 25, 2005. No dividends were declared during the first quarter of 2004.

7. STOCK-BASED COMPENSATION

Prior to January 1, 2005, the Company used the intrinsic-value method prescribed by Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for its stock-based compensation. Under this method, no compensation expense was recorded with respect to stock options as the options were granted at an exercise price equal to the estimated fair value of the underlying common shares on the date of grant. For pro forma disclosures under SFAS No. 123, "Accounting for Stock-Based Compensation," the fair value of the options was estimated on the grant dates using the minimum-value method, because the Company was a nonpublic entity on the respective grant dates. As required by APB Opinion No. 25, compensation expense related to restricted stock awards was recognized on a graded schedule over the respective vesting periods for time-based awards based on the fair value of the underlying common stock at the date of grant. For performance-based awards, compensation was recognized on a graded schedule over the respective performance periods based on the market value of the restricted stock at each reporting period and giving consideration to the probability of achieving the performance objectives.

To enhance comparability of 2005 interim and annual financial statements with those to be reported in future years after adoption of SFAS No. 123R, Spirit Finance elected to adopt the fair-value based method of SFAS No. 123 effective January 1, 2005. Under the modified prospective transition method described by SFAS No. 148, "Accounting for Stock-Based Compensation Transition and Disclosure," Spirit Finance has recognized stock-based employee compensation cost for the first quarter of 2005 as if the fair-value based method had been used for all unvested stock-based awards outstanding at January 1, 2005 and for all new grants made in 2005. The Company has not restated prior period financial statements.

For stock options granted in 2005, the estimated grant date fair value was calculated using the Black-Scholes-Merton formula. In accordance with SFAS No. 123, this estimated fair value will be expensed over the vesting period on a straight-line basis. Compensation expense related to restricted stock awards with time-based service conditions granted in 2005 will be recognized over the vesting period on a straight-line basis based on the fair value of the underlying common stock on the date of grant. Compensation expense related to restricted stock awards with performance-related conditions granted in 2005 will be recognized on a straight-line basis over the respective performance periods using the original fair value of the underlying common stock on the date of grant, giving consideration to the probability of achieving the performance objectives. For both stock options and restricted stock awards granted in 2005, forfeitures were estimated on the grant date and will be reevaluated at each reporting period, with compensation cost recognized only for those awards expected to vest.

Unvested stock options and restricted stock awards outstanding at January 1, 2005 were originally granted in 2003 and 2004, when the Company's common stock was not publicly traded. Compensation expense for the unvested stock options will continue to be recognized using the minimum-value method. Compensation expense for unvested restricted stock will continue to be recognized on a graded schedule over the remaining vesting period based on the original fair value of the underlying common stock on the date of grant, taking into consideration the probability of achieving the performance objectives for the restricted stock with performance-related conditions.

The adoption of SFAS No. 123 did not have a material impact on the Company's financial position or results of operations. Had Spirit Finance adopted the fair-value based method in the first quarter of 2004, Spirit Finance's net income and diluted and basic net income per common share for the three months ended March 31, 2004 would not have changed from the reported amounts. Stock-based compensation expense in the first three months of 2005 totaled $202,887, which represented $201,457 for restricted stock amortization and $1,430 for stock option expense. Restricted stock amortization for the first three months of 2004 totaled $228,351. Stock-based compensation is included in "General and administrative" expenses in the Consolidated Statements of Operations.

8. NET INCOME PER COMMON SHARE

A reconciliation of the numerators and denominators used in the computation of basic and diluted net income per common share is as follows:

	Three Months Ended March 31	
	2005	2004
Net income available to common stockholders	$ 6,818,684	$ 812,031
Weighted average outstanding common shares used in the calculation of basic net income per common share(a)	67,023,019	35,538,326
Effect of unvested restricted stock	236,990	130,670
Effect of stock options(b)	183,653	
Weighted average outstanding and potentially dilutive common shares	67,443,662	35,668,996
Net income per common share:		
Basic	$ 0.10	$ 0.02
Diluted	$ 0.10	$ 0.02

(a) The increase in the number of weighted average shares outstanding between 2004 and 2005 is primarily the result of the Company's initial public offering of 30,000,000 shares of common stock.

(b) Options to purchase 30,000 shares of common stock at March 31, 2005 and options to purchase 1,290,000 shares of common stock at March 31, 2004 were outstanding but were not included in the computation of diluted net income per common share for the three months ended March 31, 2005 and 2004, respectively, because the effect was not dilutive.

9. COMPREHENSIVE INCOME

Comprehensive income is comprised of net income, adjusted for changes in unrealized gains or losses on derivative financial instruments or securities classified as available-for-sale. The reconciliation

of net income to comprehensive income for the three months ended March 31, 2005 and 2004 is as follows:

	Three Months Ended March 31	
	2005	2004
Net income as reported	$ 6,818,684	$ 812,031
Net unrealized gain on cash flow hedges	1,836,183	
Net unrealized gain on available-for-sale securities		565
Comprehensive income	$ 8,654,867	$ 812,596

10. RELATED PARTY TRANSACTIONS

The Company's Chief Executive Officer is a member of the board of directors of the lessee of four interstate travel plazas owned by Spirit Finance. Rental revenues totaled approximately $900,000 for the three months ended March 31, 2005 and 2004 under this lease.

One of the Company's independent directors is a member of the board of directors of a customer operating the underlying properties that collateralize approximately half of the mortgage loans receivable held by Spirit Finance. In addition, Spirit Finance owns four properties leased by this customer. Interest income on the mortgage loans receivable and rental revenue on the lease aggregated approximately $500,000 for the three months ended March 31, 2005 and 2004.

11. COMMITMENTS AND CONTINGENCIES

Spirit Finance has contractual commitments totaling $9,654,000 at March 31, 2005 for future improvements on properties the Company currently owns. These improvements include costs incurred on facilities during which the tenant's business continues to operate without interruption and advances for the construction of new facilities for which operations have not commenced. In accordance with the underlying lease agreements, most of these improvements are anticipated to be completed during 2005 and will result in increases in related contractual rent. In addition, the Company had a binding contractual commitment of $10,867,000 at March 31, 2005 to acquire four real estate properties.

The Company may be subject to claims or litigation in the ordinary course of business. At March 31, 2005, there were no outstanding claims against the Company that would have a material adverse effect on the Company's financial position or results of operations.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's discussion and analysis of financial condition and results of operations are more clearly understood when read in conjunction with the accompanying unaudited consolidated financial statements and notes thereto as of March 31, 2005 and our audited financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2004. Undue reliance should not be placed upon historical financial statements since they are not indicative of expected results of operations or financial condition for any future periods.

Overview

Spirit Finance Corporation (NYSE: SFC) is a self-managed and self-advised REIT formed as a Maryland corporation on August 14, 2003. We were formed to acquire single tenant, operationally essential real estate leased to retail, distribution and service-oriented companies on a long-term basis. Operationally essential real estate includes land and buildings vital to the generation of our customers' sales and profits. In addition, we may selectively originate and acquire long-term mortgage loans or equipment loans that are integral to our strategy of providing a complete financing solution to our customers. We may also make a limited amount of unsecured corporate loans to our customers. Our objective is to acquire or finance the real estate of companies that provide goods and services to consumers through retail, distribution and service locations throughout the United States, such as restaurants, interstate travel plazas, movie theaters, automotive parts stores and services facilities, drugstores, educational facilities, specialty retailers and other similar businesses.

As of March 31, 2005, 94% of our $697.6 million portfolio represented real estate we own (including the gross cost of land, buildings and related lease intangibles) and 6% represented mortgage loans receivable. Our portfolio of 380 owned or financed single tenant properties is geographically diversified across 38 states. Only three states, Texas (11.1%), Arizona (10.5%) and Georgia (10.0%), accounted for 10% or more of the total dollar value of our real estate and mortgage loan portfolio. Our properties are leased or financed to 55 customers operating in various industries. Our three largest property types at the end of March 2005 as a percentage of gross real estate investments were restaurants (39%), movie theaters (17%) and specialty retailer properties (13%). Our top 10 customers as a percentage of our total portfolio at March 31, 2005 were Carmike Cinemas, Inc., Gander Mountain Company, AMC Entertainment, Inc., Rite Aid Corporation, Hughes Supply, Inc., Flying J Inc., Fuddruckers, Inc., Grand Canyon University, Dickinson Theaters, Inc. and RTM Restaurant Group (an operator of Arby's Restaurants). These customers accounted for 53% of our total portfolio investments at March 31, 2005, with no individual credit exposure greater than 6.2% of the total portfolio. As of March 31, 2005, all of our properties were occupied, and rental and mortgage payments were current.

We expect to grow through continuing our strategy of acquiring single tenant, operationally essential real estate principally through sale-leaseback transactions. We intend to fund future real estate investments primarily with borrowings on our secured credit facilities and by raising funds through the issuance of debt and additional equity capital as described below in the section entitled "Liquidity and Capital Resources." Our ability to generate positive cash flow will depend heavily on the difference between the income earned on our assets and the interest expense incurred on our borrowings.

Our ability to achieve continued growth is dependent on achieving a substantial volume of acquisitions at yields that can be effectively financed to meet our targeted returns. The current environment for net lease real estate acquisitions is competitive. We may delay or decline opportunities if we feel the rewards do not warrant the capital risk. In addition, the timing on closing acquisitions may vary significantly from quarter to quarter. The highly competitive triple-net lease environment could limit both the number of properties acquired and the yield on those acquisitions. In response to these challenges, we are committed to seeking numerous potential investment opportunities through our sales force. We continue to seek opportunities to combine our cost of capital and operational structure with efficient leverage strategies to deliver competitively priced lease products.

Liquidity and Capital Resources

In connection with our initial public offering of 26.1 million shares of our common stock at a price of $11 per share in December 2004, the underwriters exercised their over-allotment option and we issued an additional 3.9 million shares of common stock on January 7, 2005 for $40.1 million, net of underwriters' discount and offering costs.

During the first quarter of 2005, we acquired 12 properties through various transactions totaling $38.0 million. At March 31, 2005, we had contractual commitments totaling $9.7 million for future improvements on properties we currently own. In accordance with the underlying lease agreements, most of these improvements are anticipated to be completed during 2005 and will result in increases in related contractual rent. We also had a binding contractual commitment at March 31, 2005 totaling $10.9 million to acquire four real estate properties; this acquisition was completed in early April 2005. In addition, as of April 15, 2005, we have identified for review potential investment opportunities of more than $2 billion. The individual transactions identified for review range in size from $1 million to $100 million, with an average transaction size of $24 million. We consider investments as under review when we have signed a confidentiality agreement, we have exchanged financial information or we or our advisors are in current and active negotiations. Investments under review are generally subject to significant change and after further due diligence, we may decide not to pursue any or all of these transactions. In addition, the timing of closing any such acquisitions may vary significantly from quarter to quarter.

We generate our revenue and cash flow by leasing our real estate properties to customers and from interest income on our portfolio of mortgage loans receivable. We generally offer long-term leases that provide for payments of base rent with scheduled increases, increases based on changes in the Consumer Price Index and/or contingent rent based on a percentage of the lessee's gross sales. At March 31, 2005, the weighted average remaining initial lease term was approximately 15 years, and our leases generally provide for one or more renewal options. Less than 3% of our current lease portfolio will expire prior to 2012. Our leases are generally triple-net, which provides that the lessee is responsible for the payment of all property operating expenses, including insurance, real estate taxes and repairs and maintenance. Since our tenants generally pay the property operating and maintenance costs, we believe that funds for maintenance and other capital expenditures on the properties will not be significant. Substantially all of the Company's real estate investments are pledged as collateral under our debt obligations as described below.

Cash from operating activities totaled $8.9 million for the three months ended March 31, 2005. Our operating costs include interest expense on our debt and certain general and administrative costs of acquiring and managing our real estate investment portfolio, such as the compensation and benefit costs of our employees, professional fees such as legal and portfolio servicing costs and office expenses such as rent and other office operating costs. Noncash expenses include depreciation expense on the buildings and improvements in our real estate portfolio, stock-based compensation (included in general and administrative expenses) and amortization of deferred financing costs (included in interest expense).

During the first quarter of 2005, we declared dividends of $0.19 per share, payable to shareholders of record as of April 15, 2005. This distribution, totaling $12.8 million, was paid on April 25, 2005. On January 31, 2005, a cash distribution of $0.19 per share, totaling $7.1 million, was paid to stockholders of record as of December 10, 2004 (prior to the initial public offering). We intend to make regular quarterly distributions to our stockholders so that we distribute each year all or substantially all of our REIT taxable income to avoid paying corporate level income tax and excise tax on our earnings.

During the initial years of our operations, the distributions we pay may include a return of capital. Cash for future distributions is expected to be generated from operations, although we may also borrow funds to make distributions. Our ability to pay distributions will depend on, among other things, our actual results of operations, which are dependent primarily on our receipt of payments from our leases and loans with respect to our real estate investments.

In addition to our existing $250 million secured credit facility with Bank of America Mortgage Capital Corporation, in March 2005 we established a $125 million secured credit facility with Citigroup Global Markets Realty Corporation. The facility matures in June 2005 but may be extended to September 2005 at the request of the Company. Borrowings under the facility require monthly payments of interest indexed to LIBOR, plus 1.75% and an annualized fee of 0.25% on any unborrowed balance under the facility. These credit facilities are used to fund our real estate acquisitions on a short-term basis while we acquire a pool of real estate of sufficient size to execute our long-term debt strategies.

At December 31, 2004, our debt included variable-rate mortgage notes payable totaling $140.1 million and fixed-rate debt with a carrying value of $38.7 million. We did not have any amounts outstanding under our secured credit facility at the end of 2004. During the first three months of 2005, we repaid the variable-rate mortgage notes payable using cash and borrowings under our secured credit facility. At March 31, 2005, our balance under the secured credit facilities was $58.7 million and our fixed-rate debt had a carrying value of $38.5 million. Subsequent to March 31, 2005, we borrowed an additional $32.3 million under the secured credit facilities.

We are subject to various customary operating and financial covenants under the mortgage notes payable and the secured credit facilities. The mortgage notes payable include a limitation on the Company's ability to incur additional indebtedness on the underlying secured real estate. One of the secured credit facilities includes a minimum liquidity requirement of $25 million. As of March 31, 2005, we were in compliance with these covenants and requirements. Approximately 70% of the net book value of our real estate and mortgage loan assets were pledged as collateral as of March 31, 2005 for current or future borrowings.

In the short-term, we believe that cash provided by operating activities and funds available under our secured credit facilities will be sufficient to meet our liquidity needs for the operating and financing obligations of our existing investment portfolio. In order to achieve significant growth in revenues and net income, we will need to make substantial real estate acquisitions, which will in turn require that we obtain significant additional funding beyond our currently committed external sources of liquidity. On a long-term basis, we intend to use a variety of financing methods to accomplish our goal of maintaining our borrowings at a targeted leverage ratio not to exceed 65% of our total assets. We define our leverage ratio as the ratio of our total debt to total assets. We intend to obtain additional unsecured and/or secured financing through various sources including banks, institutional investors and other lenders. We may also obtain lines of credit, bridge loans, warehouse facilities and other debt arrangements or may incur debt in the form of publicly or privately placed debt instruments. As described further in the Notes to Consolidated Financial Statements and Quantitative and Qualitative Disclosures About Market Risk, we are using interest rate derivative contracts to manage our exposure to changes in interest rates on the anticipated term debt. Substantially all of our properties will be used to secure our debt financings. In addition, our ability to achieve continuous real estate investment growth will also depend on our ability to raise additional equity capital.

Results of Operations

Comparison of the Three Months Ended March 31, 2005 to the Three Months Ended March 31, 2004

We commenced operations on August 14, 2003. Our first quarter 2004 results of operations do not include significant operating data, as the majority of our real estate acquisitions were made after the first quarter of 2004.

Net income. Net income for the three months ended March 31, 2005 was $6.8 million, or $0.10 per diluted share, based on 67.4 million weighted average shares of common stock outstanding. Net income for the three months ended March 31, 2004 was $0.8 million or $0.02 per diluted share, based on 35.7 million weighted average shares of common stock outstanding. The increase in the number of weighted average shares outstanding is primarily the result of our initial public offering of 30 million common shares.

Revenues. Total revenues for the first three months of 2005 were $15.6 million as compared to total revenues of $2.6 million for the first three months of 2004. Approximately 92% of the total revenues generated in the first three months of 2005 were rental revenues from real estate properties we own and lease to our customers. Rental revenue, including net straight-line rent of $0.2 million, totaled $14.3 million for the first three months of 2005 on weighted average real estate investments of approximately $642.8 million. Rental revenue totaled almost $1.0 million for the first three months of 2004, including $0.1 million of net straight-line rent, on weighted average real estate investments of approximately $38.5 million. Approximately 37% of total revenues for the first three months of 2004 was generated by four interstate travel plaza facilities under a single master operating lease agreement. As a result of the growth in our portfolio due to the acquisition of properties during 2004 and 2005, rental revenue generated from this lessee represented less than 10% of total revenues in the first quarter of 2005.

Interest income on mortgage loans receivable totaled $0.9 million for the quarter in both 2005 and 2004. The mortgage loans represent two borrowers, with approximately half of the interest income for the period generated by each borrower. Other interest income, totaling $0.4 million for the first three months of 2005 and $0.6 million for the first three months of 2004, represents income generated on temporary investment securities pending investment in real estate.

Expenses. General and administrative expenses included the following (in millions):

	Three Months Ended March 31	
	2005	**2004**
e-related expenses(a)	$ 1.4	$ 0.9
nal fees and outsourced services	0.6	0.4

cal-align:bottom;padding-left:2px;padding-top:2px;padding-bottom:2px;padding-right:2px;">	Marcellus	Utica	CBM	Other Gas	
	Segment	Segment	Segment	Segment	Tota
ed Net Proved Reserves (MMcfe)	4,235,212	495,290	1,467,194	629,920	6,82
Developed	32 %	33 %	74 %	92 %	47
ducing Wells (including oil and gob wells)	196	22	4,374	8,360	12,95
reage Position:					
ved Developed Acres	19,675	2,822	257,543	235,400	515,
ved Undeveloped Acres	44,299	7,207	9,023	3,272	63,80
proved Acres(1)	376,837	216,302	2,122,397	1,218,439	3,93
l Net Acres(2)	440,811	226,331	2,388,963	1,457,111	4,51

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(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable. See Risk Factors in Section 1A of this Form 10-K.

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

Producing Wells and Acreage

Most of our development wells and proved acreage are located in Virginia, West Virginia and Pennsylvania. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments or other term commitments are satisfied. The following table sets forth, at December 31, 2014, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Gas Wells (including gob wells)	17,044	12,918
Producing Oil Wells	154	34
Net Acreage Position		
Proved Developed Acreage	537,935	515,439
Proved Undeveloped Acreage	112,617	63,801
Unproven Acreage	4,946,174	3,933,975
Total Acreage	5,596,726	4,513,215

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable. See Risk Factors in Section 1A of this Form 10-K.

The following table represents the terms under which we hold these acres:

	Net Unproved Acres	Net Proved Undeveloped Acres
Held by production/fee	3,792,960	49,756
Expiration within 2 years	39,385	2,665
Expiration beyond 2 years	101,630	11,380
Total Acreage	3,933,975	63,801

The leases reflected above as Net Unproved Acres with expiration dates are included in our current drill plan or active land program. Leases with expiration dates within two years represent less than 1% of our total acres in the above categories and leases with expiration dates beyond two years represent less than 3% of our total acres in the above categories. In each case, we deemed this acreage to not be material to our overall acreage position. Additionally, based on our current drill plans and lease management we do not anticipate any material impact to our consolidated financial statements from the expiration of such leases.

Development Wells (Net)

During the years ended December 31, 2014, 2013 and 2012 we drilled 180.3, 139.8 and 95.5 net development wells, respectively. Gob wells and wells drilled by operators other than our primary joint venture partners, Noble Energy and Hess Corporation, are excluded from net development wells. In 2014, there were 287 gross development wells. There were no dry development wells in 2014, 2013, or 2012. As of December 31, 2014, there are 52 net developmental wells still in process. The following table illustrates the net wells drilled by well classification type:

	For the Year Ended December 31,		
	2014	2013	2012
Marcellus segment	84.0	56.0	44.0
Utica segment	18.8	9.0	—
CBM segment	75.0	63.8	42.5
Other Gas segment	2.5	11.0	9.0
Total Development Wells (Net)	180.3	139.8	95.5

Exploratory Wells (Net)

During the years ended December 31, 2014, 2013 and 2012, we drilled, in the aggregate, 8.5, 5.5, and 22.0 net exploratory wells, respectively. As of December 31, 2014, there are 2.5 net exploratory wells in process. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2014			2013			2012		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
Marcellus segment	0.5	—	—	2.5	—	—	1.0	—	—
Utica segment	—	—	2.0	3.0	—	—	5.5	0.5	—
CBM segment	—	—	—	—	—	—	—	—	—
Other Gas segment	5.0	—	1.0	—	——	—	6.0	9.0	—
Total Exploratory Wells (Net)	5.5	—	3.0	5.5	—	—	12.5	9.5	—

Reserves

The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of royalty interest. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and proved undeveloped reserves are defined by the Securities and Exchange Commission (SEC).

	Net Reserves (Million cubic feet equivalent) as of December 31,		
	2014	2013	2012
Proved developed reserves	3,198,706	2,514,294	2,165,483
Proved undeveloped reserves	3,628,910	3,216,920	1,827,975
Total proved developed and undeveloped reserves(a)	6,827,616	5,731,214	3,993,458

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

Discounted Future Net Cash Flows

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

	Discounted Future Net Cash Flows (Dollars in millions)		
	2014	2013	2012
Future net cash flows	$9,321	$6,568	$2,792
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$4,884	$2,780	$1,242
Total standardized measure of after tax discounted future net cash flows	$2,984	$1,681	$736

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

Reconciliation of PV-10 to Standardized Measure

	As of December 31,		
	2014	2013	2012
	(Dollars in millions)		
Future cash inflows	$28,503	$21,603	$11,778
Future production costs	(10,101)	(7,106)	(4,824)
Future development costs (including abandonments)	(3,369)	(3,903)	(2,451)
Future net cash flows (pre-tax)	15,033	10,594	4,503
10% discount factor	(10,149)	(7,814)	(3,261)
PV-10 (Non-GAAP measure)	4,884	2,780	1,242
Undiscounted income taxes	(5,712)	(4,026)	(1,711)
10% discount factor	3,812	2,927	1,205
Discounted income taxes	(1,900)	(1,099)	(506)
Standardized GAAP measure	$2,984	$1,681	$736

Gas Production

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

	For the Year Ended December 31,		
	2014	2013	2012
GAS			
Marcellus Sales Volumes (MMcf)	99,370	55,048	35,853
Utica Sales Volumes (MMcf)	10,303	531	3
CBM Sales Volumes (MMcf)	79,459	82,867	88,149
Other Sales Volumes (MMcf)	27,128	30,291	31,047
LIQUIDS*			
NGLs Sales Volumes (MMcfe)	15,475	2,628	610
Oil Sales Volumes (MMcfe)	681	634	600
Condensate Sales Volumes (MMcfe)	3,298	381	63
TOTAL (MMcfe)	235,714	172,380	156,325

*Oil, NGLs, and Condensate are converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas.

CONSOL Energy projects its 2015 natural gas production, net to CONSOL, to be 300 – 310 Bcfe, or 30% growth compared to 2014 total production, when using the midpoint of the range. CONSOL Energy continues to expect 2016 annual gas production to grow by 30%.

Average Sales Price and Average Lifting Cost

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

	For the Year Ended December 31,		
	2014	2013	2012
Total Average Gas Sales Price Before Effects of Financial Settlements (per Mcfe)	$4.26	$3.85	$3.00
Average Effects of Financial Settlements (per Mcfe)	$0.11	$0.45	$1.22
Total Average Gas Sales Price Including Effects of Financial Settlements (per Mcfe)	$4.37	$4.30	$4.22
Average Lifting Costs excluding ad valorem and severance taxes (per Mcfe)	$0.50	$0.56	$0.58

Sales of NGLs, condensates, and oil enhance our reported gas equivalent sales prices. Across all volumes, sales of liquids added $0.24 per Mcfe, $0.13 per Mcfe, and $0.05 per Mcfe for 2014, 2013, and 2012, respectively, to average gas sales prices. CONSOL Energy expects to continue to realize a liquids uplift benefit as additional wells are brought online in the liquid-rich areas of the Marcellus and Utica shales. We continue to sell the majority of our NGLs through the large midstream companies that process our gas. This approach allows us to take advantage of the processors' transportation efficiencies and diversified markets. CONSOL Energy's processing contracts provide for the ability to take our NGLs "in kind" and market them directly if desired. The processed purity products are ultimately sold to industrial, commercial, and petrochemical markets.

We enter into physical gas sales transactions with various counterparties for terms varying in length. Reserves and production estimates are believed to be sufficient to satisfy these obligations. In the past, we have delivered quantities required under these contracts. We also enter into various gas swap transactions. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 159.9 Bcf of our produced gas sales volumes for the year ended December 31, 2014 at an average price of $4.58 per Mcf. These gas swaps represented approximately 84.3 Bcf of our produced gas sales volumes for the year ended December 31, 2013 at an average price of $4.68 per Mcf. As of January 15, 2015, we expect these transactions will represent approximately 121.2 Bcf of our estimated 2015 production at an average price of $4.05 per Mcf and 94.7 Bcf of our estimated 2016 production at an average price of $4.11 per Mcf.

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

Midstream Gas Services

CONSOL Energy has traditionally designed, built and operated natural gas gathering systems to move gas from the wellhead to interstate pipelines or other local sales points. In addition, CONSOL Energy has acquired extensive gathering assets. CONSOL Energy now owns or operates approximately 5,000 miles of gas gathering pipelines as well as 250,000 horsepower of compression, of which, just over 75% is wholly owned with the balance being leased. Along with this compression capacity, CONSOL Energy owns and operates a number of gas processing facilities. This infrastructure is capable of delivering approximately 500 billion cubic feet per year of pipeline quality gas.

CONSOL Energy owns 50% of CONE Gathering, LLC ("CONE" or "CONE Gathering") along with Noble Energy owning the other 50% interest. CONE Gathering develops, operates and owns substantially all of both Noble Energy's and CONSOL Energy's Marcellus Shale gathering system needs. CONSOL Energy operates this equity affiliate. We believe that the network of right-of-ways, vast surface holdings and experience in building and operating gathering systems in the Appalachian basin will give CONE Gathering an advantage in building the midstream assets required to develop the joint venture's Marcellus Shale position. On September 30, 2014, CONE Midstream Partners, LP (the Partnership) closed its initial public offering of 20,125,000 common units representing limited partnership interests at a price to the public of $22.00 per unit, which included a 2,625,000 common unit over-allotment option that was exercised in full by the underwriters. The Partnership's general partner is CONE Midstream GP LLC, a wholly owned subsidiary of CONE Gathering LLC.

As a result of the IPO transaction, the Partnership received net proceeds of $412,741 from the offering, after deducting underwriting discounts and commissions, and structuring fees of $28,779 along with additional estimated offering expenses of approximately $1,230. Of the proceeds received, $203,986 was distributed to both CNX Gas Company LLC ("CNX Gas Company"), and Noble Energy on September 30, 2014.
In the Utica Shale, we and our joint venture partner, Hess, are primarily contracting with third parties for gathering services.

CONSOL Energy continues to develop a diversified portfolio of firm transportation capacity options to support our production growth plan. In September, we entered into a precedent agreement with DTE Energy and Spectra Energy for its Nexus project as an anchor shipper to transport gas from the Appalachian Basin to Midwest markets. The pipeline is expected to be placed into service in late 2017. We also benefit from the strategic location of our primary production areas in Southwest Pennsylvania, Northern West Virginia, and Eastern Ohio. These areas are served by a large concentration of major pipelines that provide us with the capacity to move our production to the major gas markets. In addition to firm transportation capacity, CONSOL Energy continues to develop a processing portfolio to support the increasing volumes from our wet production areas.

CONSOL Energy has the advantage of having gas production from CBM, which can be lower Btu than pipeline specification, as well as higher Btu Marcellus Shale production. These two types of gas can complement each other by reducing and in some cases eliminating the need for the costly processing of CBM. In addition, both our lower Btu CBM and dry Marcellus production offers an opportunity to blend ethane back into the gas stream when pricing or capacity for ethane markets dictate. In developing a diversified approach to managing ethane, CONSOL Energy has entered into ethane supply agreements and is actively discussing future outlet opportunities with a number of ethane customers and midstream companies. These measures will allow us more flexibility in bringing Marcellus Shale wells on-line at qualities that meet interstate pipeline specifications.

Natural Gas Competition

The United States natural gas industry is highly competitive and more diversified than the coal industry. CONSOL Energy competes with other large producers, as well as thousands of smaller producers, pipeline imports from Canada, and Liquefied Natural Gas (LNG) from around the globe. According to data from the Natural Gas Supply Association and the Energy Information Agency (EIA), the five largest U.S. producers of natural gas produced about 19% of dry natural gas production in the first six months of 2014. The EIA reported 487,286 producing natural gas wells in the United States in 2013, the latest year for which government statistics are available.

Natural gas has maintained market share in the U.S. electric generation market compared to 2013 (based on preliminary 2014 results). However, we expect natural gas to become a more significant contributor to the domestic electric generation mix in the long-term, as well as fuel industrial growth in the U.S. economy. There is potential for natural gas to become a significant contributor to the transportation market. Additionally, the U.S. is expected to become a net exporter of gas in the next few years. Our increasing gas production will allow CONSOL Energy to participate in these growing markets.

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

Continued demand for CONSOL Energy's natural gas and the prices that CONSOL Energy obtains are affected by natural gas use in the production of electricity, U.S. manufacturing and the overall strength of the economy, environmental and government regulation, technological developments and the availability and price of competing alternative fuel supplies.

DETAIL COAL OPERATIONS

Coal Reserves

At December 31, 2014, CONSOL Energy had an estimated 3.2 billion tons of proven and probable reserves, excluding equity affiliates. Reserves are the portion of the proven and probable tonnage that meet CONSOL Energy's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels.

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

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

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

Our estimate of proven and probable coal reserves has been determined by CONSOL Energy’s geologists and mining engineers. CONSOL Energy geologists and mining engineers completed an extensive re-evaluation of the longwall mineable Pittsburgh and Illinois No. 5 seams during 2014. The re-evaluations included the use of mine specific assumptions and mine plans versus general mine recovery factors and general parameters. To date, approximately 50% of CONSOL Energy’s reserves have been re-evaluated using mine specific parameters as opposed to an assumed average mining recovery factors. The 2014 re-evaluations resulted in 460 million of the total 471 million additional tons of proven and probable reserves added as result of revisions and other changes in 2014 (See Supplemental Coal Data in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K).

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

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

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

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

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

Mining Complexes

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

CONSOL ENERGY MINING COMPLEXES

Proven and Probable Assigned and Accessible Coal Reserves as of December 31, 2014 and 2013

Mine/Reserve	Preparation Facility Location	Reserve Class	Coal Seam	Average Seam Thickness (feet)	As Received Heat Value(1) (Btu/lb) Typical	Range	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2014(4)	12/31/(2
ASSIGNED–OPERATING										
PA Operations										
Bailey (3)	Enon, PA	Assigned Operating	Pittsburgh	7.6	12,930	12,800 – 13,050	53%	47%	84.0	96.9
		Accessible	Pittsburgh	7.5	12,930	12,720 – 13,190	78%	22%	170.5	278.7
Harvey (3)	Enon, PA	Assigned Operating	Pittsburgh	6.6	13,040	12,940 – 13,230	89%	11%	27.1	—
		Accessible	Pittsburgh	7.6	12,930	12,870 – 13,160	99%	1%	181.2	—
Enlow Fork (3)	Enon, PA	Assigned Operating	Pittsburgh	7.8	12,920	12,800 – 13,000	99%	1%	21.6	16.9
		Accessible	Pittsburgh	7.6	12,980	12,720 – 13,120	76%	24%	301.2	232.8
VA Operations										
Buchanan	Mavisdale, VA	Assigned Operating	Pocahontas 3	6.0	13,790	13,690 – 14,050	20%	80%	44.8	47.2
		Accessible	Pocahontas 3	5.9	13,760	13,690 – 13,900	15%	85%	47.3	46.1
Amonate Complex	Amonate, VA	Assigned Operating	Multiple	4.3	13,150	12,850 – 13,350	69%	31%	15.8	20.1
		Accessible	Multiple	6.4	12,880	12,880 – 12,880	100%	—%	3.9	6.6
Other Operations										
Amvest Fola Complex (3)	Bickmore, WV	Assigned Operating	Multiple	4.6	12,380	12,250 – 12,550	86%	14%	73.4	73.4
Miller Creek Complex	Delbarton, WV	Assigned Operating	Multiple	2.6	12,100	11,600 – 12,650	40%	60%	52.0	52.6
		Accessible	Multiple	5.1	12,650	12,650 – 12,650	—%	100%	0.8	0.7
Total Assigned Operating and Accessible									1,023.6	872.0

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(1) The heat value shown for Assigned Operating reserves is based on the quality of coal mined and processed during the year ended December 31, 2014. The heat values shown for Accessible Reserves are based on as received, dry values obtained from drill hole analyses, adjusted for moisture, and prorated by the associated Assigned Operating product values to account for similar mining and processing methods.

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

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

(4) The table excludes both 55.0 million tons of recoverable reserves held by an equity affiliate of which CONSOL Energy owns a 49% interest and approximately 118.8 million tons of reserves at December 31, 2014 that are assigned to projects that have not produced coal in 2014. These assigned reserves are in the Northern Appalachia (Pennsylvania, Ohio and Northern West Virginia), Central Appalachia (Virginia and Southern West Virginia) and Western U.S. (Utah) and are approximately 71% owned and 29% leased.

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

CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of December 31, 2014 and 2013

		Recoverable Reserves(2)			Recoverable Reserves (Tons in Millions)
Coal Producing Region	As Received Heat Value(1) (Btu/lb)	Owned (%)	Leased (%)	Tons in Millions 12/31/2014	12/31/2013
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)	11,400 – 13,600	87%	13%	1,219.1	951.7
Central Appalachia (Virginia, Southern West Virginia)	11,400 – 14,100	51%	49%	321.2	349.6
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,600 – 12,000	53%	47%	555.6	731.9
Total		72%	28%	2,095.9	2,033.2

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

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

The following table classifies CONSOL Energy coals by rank, projected sulfur dioxide emissions and heating value (British thermal units per pound). The table also classifies bituminous coals as high, medium and low volatile which is based on fixed carbon and volatile matter.
CONSOL Energy Proven and Probable Recoverable Coal Reserves
By Product (In Millions of Tons) As of December 31, 2014

	≤ 1.20 lbs. S02/MMBtu			> 1.20 ≤ 2.50 lbs. S02/MMBtu			> 2.50 lbs. S02/MMBtu				
By Region	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Total	Percent By Product
Metallurgical(1):											
High Vol A Bituminous	—	—	6.3	—	—	208.7	—	—	—	215.0	6.6 %
Med Vol Bituminous	—	5.1	56.0	—	—	2.9	—	—	—	64.0	2.0 %
Low Vol Bituminous	—	—	126.8	—	—	73.7	—	—	—	200.5	6.2 %
Total Metallurgical	—	5.1	189.1	—	—	285.3	—	—	—	479.5	14.8 %
Thermal(1):											
High Vol A Bituminous	31.4	80.4	4.6	38.2	105.2	62.3	66.7	1,077.0	703.0	2,168.8	67.0 %
High Vol B Bituminous	—	17.7	—	—	113.4	—	—	186.7	—	317.8	9.8 %
High Vol C Bituminous	—	—	—	—	159.4	—	108.3	—	—	267.7	8.3 %
Low Vol Bituminous	—	—	—	—	—	—	—	—	4.5	4.5	0.1 %
Total Thermal	31.4	98.1	4.6	38.2	378.0	62.3	175.0	1,263.7	707.5	2,758.8	85.2 %
Total	31.4	103.2	193.7	38.2	378.0	347.6	175.0	1,263.7	707.5	3,238.3	100.0 %
Percent of Total	1.0 %	3.2 %	6.0 %	1.2 %	11.7 %	10.7 %	5.4 %	39.0 %	21.8 %	100.0 %	

The table above excludes 55.0 million tons of recoverable reserves held by an equity affiliate of which CONSOL Energy owns a 49% interest.

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

The following table sets forth, with respect to properties that we lease to other coal operators, the total royalty tonnage, acreage leased and the amount of income (net of related expenses) we received from royalty payments for the years ended December 31, 2014, 2013 and 2012.

	Total Royalty	Total Coal	Total Royalty

Year	Tonnage (in thousands)	Acreage Leased	Income (in thousands)
2014	10,230	281,894	$18,460
2013	8,335	271,755	$16,906
2012	8,326	271,760	$16,853

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

Production

In the year ended December 31, 2014, 93% of CONSOL Energy's production from continuing operations came from underground mines and 7% from surface mines. CONSOL Energy employs longwall mining systems in our underground mines where the geology is favorable and reserves are sufficient. For the year ended December 31, 2014, 93% of our production came from mines equipped with longwall mining systems. Underground longwall systems are highly mechanized, capital intensive operations. Mines using longwall systems have a low variable cost structure compared with other types of mines and can achieve high productivity levels compared with those of other underground mining methods. Because CONSOL Energy has substantial reserves readily suitable to these operations, CONSOL Energy believes that these longwall mines can increase capacity at a low incremental cost.
The following table shows the production from continuing operations, in millions of tons, for CONSOL Energy's mines for the years ended December 31, 2014, 2013 and 2012, the location of each mine, the type of mine, the type of equipment used at each mine, method of transportation and the year each mine was established or acquired by us.

Mine	Preparation Facility Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2014	2013	2012	Year Established or Acquired
PA Operations								
Bailey (3)	Enon, PA	U	LW/CM	R R/B	12.3	10.8	10.1	1984
Enlow Fork (3)	Enon, PA	U	LW/CM	R R/B	10.6	10.1	9.5	1990
Harvey (5)	Enon, PA	U	LW/CM	R R/B	3.2	0.6	—	2014
VA Operations								
Buchanan (1)	Mavisdale, VA	U	LW/CM	R T	4.0	4.8	3.5	1983
Amonate (1)(2)	Amonate, VA	U/S	A/S/CM	R T	—	—	0.1	2012
Other								
Miller Creek Complex (2)	Delbarton, WV	U/S	CM/S/L	R T	2.1	2.2	2.9	2004
AMVEST-Fola Complex (1)(2)	Bickmore, WV	U/S	A/S/L/CM	R T	—	—	1.1	2007
Total					32.2	28.5	27.2	
CONSOL Energy Portion of Equity Affiliates								
Harrison Resources (2)(4)	Cadiz, OH	S	S/L	R T	0.3	0.4	0.4	2007
Western Allegheny (2)(4)	Young Township, PA	U	CM	R T	0.5	0.3	0.1	2010
Total CONSOL Energy Portion of Equity Affiliates					0.8	0.7	0.5	

A – Auger
S – Surface
U – Underground
LW – Longwall
CM – Continuous Miner
S/L – Stripping Shovel and Front End Loaders
R – Rail
R/B – Rail to Barge
T – Truck
(1) – Mine was idled for part of the year(s) presented due to market conditions.
(2) – Harrison Resources, Miller Creek Complex, AMVEST–Fola Complex, Amonate Complex and Western Allegheny (includes facilities operated by independent contractors).

(3) – Mine was idle for three weeks during 2012 due to a structural failure at the above-ground conveyor system at the Bailey Preparation Plant. Production later resumed at a reduced capacity.

(4) – Production amounts represent CONSOL Energy's 49% ownership interest. Interest in Harrison Resources was sold on October 1, 2014.

(5) – Completed development work and was placed in service in March 2014.

Coal Capital

In 2015, CONSOL Energy expects to invest $220 million in the Coal and other Division: $160 million in maintenance of production capital, and $60 million in land, safety, water, terminal operations, and other miscellaneous categories.

Coal Marketing and Sales

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

	Years Ended December 31,		
	2014	2013	2012
Average Sales Price Per Ton Sold– PA Operations	$61.88	$63.93	$67.67
Average Sales Price Per Ton Sold– VA Operations	$71.80	$92.43	$140.11
Average Sales Price Per Ton Sold– Other Operations	$60.12	$70.22	$71.44
Average Sales Price Per Ton Sold– Total Company	$63.03	$69.34	$77.75

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

A breakdown of total coal sales from continuing operations is as follows:

	Tons Sold	Percent of Total	
PA Operations	26.1	81	%
VA Operations	4.1	13	%
Other Operations	2.2	6	%
Total tons sold	32.4	100	%

Approximately 72% of our 2014 coal sales from continuing operations were made to U. S. electric generators, 5% of our 2014 coal sales were priced on export markets and 23% of our coal sales were made to other domestic customers. We had over 50 customers from our 2014 coal operations. During 2014, Duke Energy and Xcoal Energy Resources each comprised over 10% of our revenues from continuing operations, and the top four coal customers accounted for more than 30% of our total revenues from continuing operations.

Coal Contracts

We sell coal to an established customer base through opportunities as a result of strong business relationships, or through a formalized bidding process. Contract volumes range from a single shipment to multi-year agreements for millions of tons of coal. The average contract term is between one to three years. As a normal course of business, efforts are made to renew or extend contracts scheduled to expire. Although there are no guarantees, we generally have been successful in renewing or extending contracts in the past. For the year ended December 31, 2014, over 66% of all the coal we produced from continuing operations was sold under contracts with terms of one year or more.

The following table sets forth as of January 18, 2015, CONSOL Energy's estimated production and sales for 2015 through 2016.

COAL DIVISION GUIDANCE
(Tons in millions)

	Q1 2015	2015	2016
Estimated Total Coal Sales	8.0 - 8.5	30.5 - 33.0	30.5 - 33.0
Tonnage: Firm	7.3	24.2	13.4
Price: Sold (firm)	$62.24	$63.06	$63.12
Estimated PA Operations Sales	6.6 - 6.8	24.9 - 26.6	24.9 - 26.6
Tonnage: Firm	5.9	20.7	11.8
Estimated VA Operations Sales	1.0 - 1.2	3.7 - 4.2	3.7 - 4.2
Tonnage: Firm	0.9	1.6	0.8
Estimated Other Sales	0.4 - 0.5	1.9 - 2.2	1.9 - 2.2
Tonnage: Firm	0.5	1.9	0.8

Note: While most of the data in the table are single point estimates, the inherent uncertainty of markets and mining operations means that investors should consider a reasonable range around these estimates. CONSOL Energy has chosen not to forecast prices for open tonnage due to ongoing customer negotiations. Firm tonnage is tonnage that is both sold and priced, and excludes collared tons. There are no collared tons in 2015. Collared tons in 2016 are 0.9 million tons, with a ceiling of $61.46 per ton and a floor of $57.54 per ton. Not included in the category breakdowns are the tons from Western Allegheny Energy (WAE). WAE has 0.1 million tons for Q1 2015, and 0.5 million tons and 0.4 million tons for all of 2015, and 2016, respectively.

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

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

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

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

Distribution

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

Coal Competition

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. CONSOL Energy competes against several other large producers and numerous small producers in the United States and overseas. Demand for our coal by our principal customers is affected by many factors including:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power, wind or solar;
- environmental and government regulation;

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- coal quality;
- transportation costs from the mine to the customer;
- the reliability of fuel supply;
- worldwide demand for steel;
- natural/weather disasters; and
- political changes in international governments.

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

Other Operations

CONSOL Energy provides other services both to our own operations and to others. These include land services, coal terminal services and water services.

Non-Core Mineral Assets and Surface Properties

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

Terminal Services

In 2014, approximately 9.6 million tons of coal were shipped through CONSOL Energy's subsidiary, CNX Marine Terminals Inc.'s, exporting terminal in the Port of Baltimore. Approximately 42% of the tonnage shipped was produced by CONSOL Energy coal mines. The terminal can either store coal or load coal directly into vessels from rail cars. It is also one of the few terminals in the United States served by two railroads, Norfolk Southern Corporation and CSX Transportation Inc.

Water Services

CNX Water Assets LLC, a CONSOL Energy subsidiary, is acquiring and developing existing sources of water in order to support our gas and coal operations, develop business in water sales, promote cutting edge water technologies, treat both acid mine drainage (AMD) water and fracturing water, and reduce our environmental liabilities. CNX Water Assets' operate an advanced waste water treatment plant in support of coal operations as well as fresh water reservoirs. CNX Water Assets' objective is to develop and maximize the value of existing water assets, which will be used to provide water for drilling and hydraulic fracturing in support of gas operations and meeting the needs of mining operations. CNX Water Assets' also has contracts to provide water to third parties for industrial use from various water sources owned by CONSOL Energy.

Employee and Labor Relations

At December 31, 2014, CONSOL Energy had 3,834 employees. Less than 1% of the total workforce is represented by the United Mine Workers of America (UMWA).

Industry Segments

Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2014, 2013 and 2012 is included in Note 25 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

Laws and Regulations

Overview

Our gas and coal mining operations are subject to various types of federal, state and local laws and regulations. Regulations relating to our operations include permitting and other licensing requirements; water withdrawal and procurement for well stimulation purposes; well drilling and casing; well production; well plugging; venting or flaring of natural gas; pipeline compression and transmission of natural gas and liquids; reclamation and restoration of properties after gas or mining operations are completed; storage, transportation and disposal of materials used or generated by gas and mining operations; the calculation, reporting and disbursement of taxes; gathering of gas production in certain circumstances; surface subsidence from underground mining; discharge of water from coal mining operations; air quality standards; protection of wetlands; endangered plant and wildlife protection; and employee health and safety. Numerous governmental permits and approvals under these laws and regulations are required for gas and mining operations. Lastly, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our gas and coal products.

Compliance with these laws has substantially increased the cost of gas production and mining of coal for all domestic gas and coal producers. We also post performance bonds or letters of credit pursuant to state oil and gas laws and regulations to guarantee reclamation of gas well sites and plugging of gas wells. We post surety performance bonds or letters of credit pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, often including the cost of treating mine water discharge. We endeavor to conduct our gas and mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements against a backdrop of variable geologic and seasonal conditions, permit exceedances and violations during gas and mining operations can and do occur. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on our gas and coal mining operations or our customers' ability to use our gas and coal and may require us or our customers to change their operations significantly or incur substantial costs.

CONSOL Energy is committed to complying with all laws and regulations. This commitment is evident in CONSOL Energy's demonstrated cost and effort to abate and control pollution and/or contamination at its facilities. CONSOL Energy made capital expenditures for environmental control facilities of approximately $19.0 million, $1.6 million, and $1.3 million in the years ended December 31, 2014, 2013 and 2012, respectively. CONSOL Energy expects to have capital expenditures of $19.9 million in 2015 for environmental control facilities.

Environmental Laws

Clean Air Act and Related Regulations. The federal Clean Air Act (CAA) and corresponding state laws and regulations regulate air emissions primarily through permitting and/or emissions control requirements. This affects gas production and processing operations as well as coal mining and coal handling and processing.

We are required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions. On August 16, 2012, the U.S. Environmental Protection Agency (EPA) published final revisions to the New Source Performance Standards (NSPS) to regulate emissions of volatile organic compounds (VOCs) and sulfur dioxide (SO_2) from various oil and gas exploration, production, processing and transportation facilities and revisions to the National Emission Standards for Hazardous Air Pollutants (NESHAPS) to further regulate emissions from the oil and natural gas production sector and the transmission and storage of natural gas. Section 111 of the CAA authorized the EPA to develop technology based standards which apply to specific categories of stationary sources. In September 2009, the

EPA finalized the Mandatory Reporting of Greenhouse Gas Rule. The current version of this rule requires annual reporting of emissions from gas wells, coal mines and associated facilities.

The U.S. EPA is currently proposing to amend the Petroleum and Natural Gas Systems source category (Subpart W) of the Greenhouse Gas Reporting Program (GHGRP). This proposed rule would add reporting of greenhouse gas emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The rule would also require operators to install new monitoring equipment during the next year in order to comply with Subpart W. In addition, on January 14, 2014, the Obama Administration announced its goal to significantly reduce methane emission from oil and gas sources by 2014. As part of this announcement, the EPA announced that it will issue a proposed rule in the summer of 2015 and a final rule in 2016 setting standards for methane and VOC emissions from new and modified oil and gas productions sources and natural gas processing and transmission sources.

The CAA also indirectly and more significantly affects the U.S. coal industry by extensively regulating the air emissions of coal-fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide, a greenhouse gas, is also emitted when coal is burned. Environmental regulations governing emissions from coal-fired electric generating plants increase the costs to operate and could affect demand for coal as a fuel source and affect the volume of our sales. Moreover, additional environmental regulations increase the likelihood that existing coal-fired electric generating plants will be decommissioned, including plants to which CONSOL Energy sells coal to, and reduce the likelihood that new coal-fired plants will be built in the future.

In early 2012, the EPA promulgated or finalized several rules for new source performance standards (NSPS) for coal- and oil- fired power plants and these changes affect coal-generating facilities. The Utility Maximum Control Technology (UMACT) rule requires more stringent NSPS for particulate matter (PM), SO_2 and NO_X and the Mercury and Air Toxics Standards (MATS) rule requires new mercury and air toxic standards. In November 2012, EPA published a notice of reconsideration of certain aspects of the UMACT and MATS rules. Following reconsideration, in April 2013, EPA promulgated final UMACT and MATS rules at which point the standards become applicable to new power plants. The final rules have higher emission limits, but the standards are still stringent and compliance with the rules is expensive.

On July 6, 2011, the EPA finalized a rule known as the Cross-State Air Pollution Rule (CSAPR). CSAPR regulates cross-border emissions of criteria air pollutants include SO2 and NOX, as well as byproducts, fine particulate matter (PM2.5) and ozone by requiring states to limit emissions from sources that "contribute significantly" to noncompliance with air quality standards for the criteria air pollutants. If the ambient levels of criteria air pollutants are above the thresholds set by the EPA, a region is considered to be in "nonattainment" for that pollutant and the EPA applies more stringent control standards for sources of air emissions located in the region. After sever years of litigation, implementation of CSAPR Phase 1 is now scheduled for 2015, with Phase 2 beginning in 2017.

In April 2012, the EPA published its proposed NSPS for carbon dioxide (CO_2) emissions from coal-powered electric generating units. The proposed rules would have applied to new power plants and to existing plants that make major modifications. If the rules had been adopted as proposed, the only new coal-fired power plants that could have met the proposed emission limits would have been coal-fired plants with CO_2 capture and storage (CCS). Commercial scale CCS is not likely to be available in the near future, and if available, it may make coal-fired electric generation units uneconomical compared to new gas-fired electric generation units. On January 8, 2014, EPA re-proposed NSPS for CO_2 for new fossil fuel fired power plants and rescinded the rules that were proposed on April 12, 2012.

On September 20, 2013, the EPA issued a new proposal to control carbon emissions from new power plants. Under the proposal, EPA would establish separate NSPS for CO_2 emissions for natural gas-fired turbines and coal-fired units. The proposed “Carbon Pollution Standard for New Power Plants” replaces an earlier proposal released by EPA in 2012.

In another proposed rulemaking related to CO_2 emissions, on June 2, 2014, EPA proposed the Clean Power Plan to cut carbon emissions from existing power plants. Under this proposed rule, EPA would create emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals.

The CAA requires EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants and the CAA identifies two types of NAAQS. Primary standards provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

On December 17, 2014, the EPA proposed a rule to lower the primary and secondary NAAQS for ozone. Under the proposal, the primary standard would be reduced from the current 0.075 ppm to a standard within the range of 0.065 ppm to 0.070 ppm. Similarly the secondary standard would be reduced to a standard within the range of 0.065 ppm to 0.070 ppm. This proposed rule could have a large impact on both the oil and gas and coal mining industries as states would be required to update their permitting standards to meet these potentially unachievable limits.

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

Pursuant to a Congressional requirement in EPA's 2010 budget appropriation, EPA must conduct a comprehensive study of the potential adverse impact that hydraulic fracturing may have on water quality and public health. Hydraulic fracturing is a way of producing gas from tight rock formations such as the Marcellus and Utica shales. The EPA initiated the study in early January 2011 with a final report originally intended to be published in 2014. EPA’s current estimate of the completion time for a draft of its study of the risks posed by hydraulic fracturing to drinking water is now projected by the agency to be completed in early 2015.

CONSOL Energy utilizes pipelines extensively for its gas, water and coal businesses, and mitigation permits from the Army Corps of Engineers (ACOE) are typically required for certain impacts to streams and wetlands. On April 21, 2014 EPA published a proposed rule called “Definition of ‘Waters of the United States’ Under the Clean Water Act.” The proposal would expand the scope of the CWA to include previously non-jurisdictional streams, wetlands, and waters, making these areas jurisdictional inter-coastal waters of the U.S. If finalized, the rulemaking will likely cause states that have jurisdiction over their own waters to make regulatory changes to their already robust regulatory programs while offering little to no added environmental protection or benefit from the changes. This would only add unwarranted delays to the permitting process and extend review times even further for regulatory agencies already under-resourced. These changes would also lead to additional mitigation cost and severely limit CONSOL Energy’s ability to avoid regulated jurisdictional waters, while extending the coverage of “waters of the United States” into areas that have no significant hydrologic connection to jurisdictional waters. We believe the proposal as written does not accomplish EPA’s goal of clarification, and has blurred the lines between what is and is not jurisdictional under the CWA.

In order to obtain a permit for surface coal mining activities, including valley fills associated with steep slope mining, an operator must obtain a permit for the discharge of fill material from the ACOE and a discharge permit from the state regulatory authority under the state counterpart to the Clean Water Act. Beginning in early 2009, the EPA implemented several initiatives that have delayed and obstructed the issuance of surface mining operation permits in the Appalachian states including Pennsylvania and Virginia where our principal mining complexes are located. Increased oversight of delegated state programmatic authority, coupled with individual permit review and additional requirements imposed by the EPA, has resulted in delays in the review and issuance of permits for surface coal mining operations, including applications for surface facilities for underground mines, such as applications for coal refuse disposal areas. The coal industry has had some success challenging EPA’s policies but EPA continues with its initiatives. Thus far, CONSOL Energy subsidiaries have been able to continue operating their existing mines. There is no assurance that permits can be obtained for future mining operations.

Resource Conservation and Recovery Act. The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect gas operations and coal mining by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed are subject to corrective action orders issued by the EPA that could adversely affect our results, financial condition and cash flows. In 2010, EPA proposed options for the regulation of Coal Combustion Residuals (CCRs) from the electric power sector as either hazardous waste or non-hazardous waste. On December 19, 2014, EPA announced the first national regulations for the disposal of CCRs from electric utilities and independent power producers under RCRA. EPA finalized these regulations under the solid waste provisions (Subtitle D) of RCRA and not the hazardous waste provisions (Subtitle C). EPA plans to publish the final rule in the Federal Register in early January 2015. EPA affirms in the preamble to the final rule that “this rule does not apply to CCR placed in active or abandoned underground or surface mines.” Instead, “the U.S. Department of Interior (DOI) and EPA will address the management of CCR in mine fills in a separate regulatory action(s).”

Endangered Species Act. The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered and threatened species may cause us to modify gas well pad siting or pipeline right of ways, mining plans, or develop and implement species-specific protection and enhancement plans to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA. Based on species that have been identified and the current application of endangered species laws and regulations, we do not believe that there are any species protected under the ESA or state laws that would materially and adversely affect our ability to produce gas or mine coal from our properties. The U.S. Fish and Wildlife Service (USFWS) announced a 12-month finding that listing of the Northern Long-Eared Bat as endangered is warranted throughout the bat’s range. CONSOL Energy, along with others in industry has submitted comments against the listing. This listing will establish habitat protection for the species but will not prevent the cause of the decline in the population of the Northern Long-Eared Bat, which is due to a disease commonly referred to as White Nose Syndrome (WNS). This will lead to significant timing and critical path hurdles, ultimately limiting the ability to clear timber for construction activities. Both the Northeast Association of Fish and Wildlife Agencies (NEAFWA) and Midwest Association of Fish and Wildlife Agencies (MAFWA) have indicated that an endangered listing is “not warranted,” but recommends it be listed as threatened due to WNS. The USFWS has stated that “A final decision on listing the northern long-eared bat will be made no later than April 2, 2015.”

Surface Mining Control and Reclamation Act. The federal Surface Mining Control and Reclamation Act (SMCRA) establishes minimum national operational and reclamation standards for all surface mines as well as most aspects of underground mines. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the U.S. Office of Surface Mining (OSM) or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the appropriate state regulatory authority. States that operate federally approved state programs may impose standards which are more stringent than the requirements of SMCRA and OSM's regulations and in many instances have done so. Our active mining complexes are located in states which have achieved primary jurisdiction for enforcement of SMCRA through approved state programs. In addition, SMCRA imposes a reclamation fee on all current mining operations, the proceeds of which are deposited in the Abandoned Mine Reclamation Fund (AML Fund), which is used to restore unreclaimed and abandoned mine lands mined before 1977. The current per ton fee is $0.28 per ton for surface mined coal and $0.12 per ton for underground mined coal. These fees are currently scheduled to be in effect until September 30, 2021.

Excess Spoil, Coal Mine Waste, Diversions, and Buffer Zones for Perennial and Intermittent Streams. OSM has issued final amendments to regulations concerning stream buffer zones, stream channel diversions, excess spoil, and coal mine waste to comply with an order issued by the U.S. District Court for the District of Columbia on February 20, 2014, which vacated the stream buffer zone rule that was published December 12, 2008. OSM has indicated that a new proposed Revised Stream Buffer Zone rule is likely in spring or summer of 2015, with a final goal for rule promulgation in December 2016.

West Virginia Above Ground Storage Tank Rules. In response to a spill by Freedom Industries of crude 4-methylcyclohexanemethanol (MCHM) to the Elk River on January 9, 2014, West Virginia signed into law Senate Bill 373 (also known as the Above Ground Storage Tank Act), which requires that all above ground storage tanks (ASTs) be registered with the Department of Environmental Protection (DEP) and meet additional requirements. West Virginia DEP filed a Final Interpretive Rule addressing initial inspection, certification and spill prevention response plan requirements on October 21, 2014. This Interpretive Rule is a temporary measure until more comprehensive rules are filed. The West Virginia DEP plans to propose additional rules for public notice and comment in the coming year. With approximately 4,000 impacted ASTs currently operational in West Virginia and more needed for the oil and gas production, these rules could have a significant financial impact on CONSOL Energy.

Federal Regulation of the Sale and Transportation of Gas

Regulations and orders set forth by the Federal Energy Regulatory Commission (FERC) impact our gas business to a certain degree. Although the FERC does not directly regulate our gas production activities, the FERC has stated that it intends for certain of its orders to foster increased competition within all phases of the natural gas industry. Additionally, the FERC continues to review its transportation regulations, including whether to allocate all short-term capacity on the basis of competitive auctions and whether changes to its long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. The FERC has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the FERC does not have jurisdiction over services provided by these facilities, then such facilities and services may be subject to regulation by state authorities in accordance with state law. We own certain natural gas pipeline facilities that we believe meet the traditional tests which the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction.

Health and Safety Laws

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

Mine Safety. Legislative and regulatory changes have required us to purchase additional safety equipment, construct stronger seals to isolate mined out areas, and engage in additional training. We have also experienced more aggressive inspection protocols and with new regulations the amount of civil penalties has increased. The actions taken thus far by federal and state governments include requiring:

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

According to a November 2013 regulatory update, the Department of Labor (DOL) intends to publish final rules for underground coal mining operations concerning proximity detection systems for continuous mining machines and rules concerning the exposure of coal miners to crystalline silica. On January 15, 2015, MSHA published a final rule requring underground coal mine operations to equip continuous mining machines, except full-face continuous mining machines, with proximity detection systems. The proximity detection system strengthens protection for miners by reducing the potential of pinning, crushing and striking hazards that result in accidents involving life-treating injuries and death. The final rule becomes effective March 15, 2015 and includes a phased in schedule for newly manufactured and in-service equipment. In 2010 MSHA rolled out the “End Black Lung, Act Now” initiative. As a result, MSHA has implemented a new final rule on August 1, 2014 to lower miners’ exposure to respirable coal mine dust including using the new Personal Dust Monitor (PDM) technology. This final rule will be implemented in three phases. The first phase began on August 1, 2014 and utilizes the current gravimetric sampling device to take full shift dust samples from the current designated occupations and areas. It also requires additional record keeping and immediate corrective action in the event of overexposure. The second phase begins on February 1, 2016 and requires additional sampling for designated and other occupations using the new continuous personal dust monitor (CPDM) technology, which provides real time dust exposure information to the miner. CONSOL Energy has ordered the necessary CPDM equipment which is required to meet compliance with the new rule at a cost of $2 million. We are also in the process of hiring Dust Coordinators and Dust Technicians to meet the staffing demand to manage compliance with the new rule at an estimated cost of $3 million. The final phase of the new rule will take effect on August 1, 2016. The current respirable dust standard will then be reduced from 2.0 to 1.5mg/m3 for designated occupations and from 1.0 to 0.5mg/m3 for Part 90 Miners.

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

- current and former coal miners totally disabled from black lung disease;
- certain survivors of a miner who dies from black lung disease or pneumoconiosis; and
-

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

The Patient Protection and Affordable Care Act (PPACA) made two changes to the Federal Black Lung Benefits Act. First, it provided changes to the legal criteria used to assess and award claims by creating a legal presumption that miners are entitled to benefits if they have worked at least 15 years in underground coal mines, or in similar conditions, and suffer from a totally disabling lung disease. To rebut this presumption, a coal company would have to prove that a miner did not have black lung or that the disease was not caused by the miner's work. Second, it changed the law so black lung benefits will continue to be paid to dependent survivors when the miner passes away, regardless of the cause of the miner's death. The changes have increased the cost to CONSOL Energy of complying with the Federal Black Lung Benefits Act. In addition to the federal legislation, we are also liable under various state statutes for black lung claims.

Other State and Local Laws Related to Our Gas Business

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

Ownership of Mineral Rights. CONSOL Energy acquires ownership or leasehold rights to gas and coal properties prior to conducting operations on those properties. As is customary in the gas and coal industries, we have generally conducted only a summary review of the title to gas and coal rights that are not in our development plans, but which we believe we control. This summary review is conducted at the time of acquisition or as part of a review of our land records to determine control of mineral rights. Given CONSOL Energy's long history as a coal producer, we believe we have a well-developed ownership position relating to our coal control; however, our ownership of oil and gas rights, particularly those rights that we acquired in connection with our historic coal operations and some of the rights we acquired in 2010 from Dominion are less developed. As we continue to review our land records and confirm title in anticipation of development, we expect that adjustments to our ownership position (either increases or decreases) will be required.

Prior to the commencement of development operations on gas and coal properties, we conduct a thorough title examination and perform curative work with respect to significant defects. We generally will not commence operations on a property until we have cured any material title defects on such property. We are typically responsible for the cost of curing any title defects. In addition, the acquisition of the necessary rights may not be feasible in some cases. Our discovering gas title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves. We have completed title work on substantially all of our gas and coal producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the industry.

Available Information

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

Executive Officers of the Registrant

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

ITEM 1A. Risk Factors

Investment in our securities is subject to various risks, including risks and uncertainties inherent in our business. The following sets forth factors related to our business, operations, financial position or future financial performance or cash flows which could cause an investment in our securities to decline and result in a loss.

Deterioration in the global economic conditions in any of the industries in which our customers operate, or a worldwide financial downturn, such as the 2008 - 2009 financial crisis, or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict.

Economic conditions in a number of industries in which our customers operate, such as electric power generation and steel making, substantially deteriorated in recent years and reduced the demand for natural gas and coal. Although global industrial activity recovered from 2009 levels, the general economic challenges for some of our customers continued in 2014 and the outlook is uncertain. In addition, liquidity is essential to our business and developing our assets. Renewed or continued weakness in the economic conditions of any of the industries served by our customers could adversely affect our business and financial condition in a number of ways. For example:

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

Prices for natural gas, natural gas liquids and coal are volatile and can fluctuate widely based upon a number of factors beyond our control including oversupply relative to the demand available for our products, weather and the price and availability of alternative fuels. An extended decline in the prices we receive for our natural gas, natural gas liquids, and coal will adversely affect our operating results and cash flows.

Our financial results are significantly affected by the prices we receive for our natural gas, natural gas liquids, oil and coal.

Natural gas, natural gas liquids and oil accounted for approximately 32% of our outside sales revenues from continuing operations in 2014. Natural gas, natural gas liquids and oil prices are very volatile and can fluctuate widely based upon supply from energy producers relative to demand for these products and other factors beyond our control. The sale to Murray Energy in 2013 of almost one half of our thermal coal production increased our exposure to fluctuations in the price of metallurgical coal, natural gas, natural gas liquids and oil.

In particular, while demand for natural gas has recovered to pre-recession levels, the U.S. natural gas industry continues to face concerns of oversupply due to the success of Marcellus and other new shale plays. The oversupply of natural gas in 2012 resulted in domestic prices hovering around ten year lows, and drilling continued in these plays, despite lower gas prices, to meet drilling commitments. Although gas prices recovered somewhat during 2013 and the first quarter of 2014, they again significantly declined in the latter part of 2014 due to oversupply.

Our gas operations are geographically concentrated in the mid-Atlantic states. The success of the Marcellus Shale play and development of other Shale plays has resulted in growth in gas production in this region with production per day in Pennsylvania, West Virginia and Ohio more than doubling since 2011. Traditionally, natural gas produced in the mid-Atlantic states sold at a premium to the benchmark Louisiana Henry Hub prices. However, as Appalachian production increased this premium narrowed and during 2014, the spot prices at some Appalachian hubs fell below Henry Hub prices. This decline, or negative basis, to the Henry Hub price is forecasted to continue in future years and may widen due to anticipated further increased Appalachian gas production. Oversupply from the continued drilling in these plays, despite lower prices, directly affects prices we receive. Thus, apart from the general impact of domestic production on overall gas prices, the price paid for our natural gas also may be adversely affected by increasing production and oversupply in our market. Low gas prices adversely impact our gas operations revenues and earnings before income taxes.

An extended period of lower natural gas prices could negatively affect us in several other ways. These include reduced cash flow, which would decrease funds available for capital expenditures employed to replace reserves or increase production. For example, in light of the low natural gas prices during 2012, the number of wells drilled in our Noble joint venture during 2012 was significantly reduced from the number we initially planned to drill. Also, our access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable. Additionally, lower natural gas prices may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. We may incur impairment charges in the future, which could have an adverse effect on our results of operations in the period taken.

We and our joint venture partners have increased drilling activity in areas of shale formations which may also contain natural gas liquids and/or oil. The prices for natural gas liquids and oil are also volatile for reasons similar to those described above regarding natural gas. As a result of increasing supply, including from shale plays, oil prices fell to five year lows during 2014. In addition, similar to the oversupply of natural gas, increased drilling activity in 2012 by third parties in formations containing natural gas liquids has led to a significant decline in the price of natural gas liquids. If we discover and produce significant amounts of natural gas liquids or oil, our results of operation may be adversely affected by downward fluctuations in natural gas liquids and oil prices.

The coal industry also faces concerns with respect to oversupply. Coal accounted for approximately 61% of our outside sales revenues from continuing operations in 2014. In 2013, our average sales price per ton of low volatile metallurgical coal fell by approximately 34% due to oversupply which was particularly acute in the international market. This trend continued in 2014 with metallurgical coal prices falling to six year lows and our average sales price of low volatile metallurgical coal further declined by another 22% from 2013’s depressed price.

Apart from issues with respect to the supply of products we produce, demand can fluctuate widely due to a number of matters beyond our control including:

- changes in the consumption pattern of industrial consumers, electricity generators and residential users;
- weather conditions in our markets which affect the demand for natural gas and thermal coal (for example, the unusually warm 2011 - 2012 winter left utilities with large coal stockpiles and depressed the demand for thermal coal);
- proximity and capacity of gas pipelines and other transportation facilities;
- the price and availability of alternative fuels, especially thermal coal; the price and supply of imported liquefied natural gas; and
- increased utilization by the steel industry of electric arc furnaces or pulverized coal processes to make steel which do not use furnace coke, an intermediate product produced from metallurgical coal, decreases the demand for metallurgical coal.

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

We compete in international markets against coal produced in other countries. Coal is sold internationally in U.S. dollars. As a result, mining costs in competing producing countries may be reduced in U.S. dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. We also expect in the future that an international market will develop for exporting domestic natural gas and natural gas liquids. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

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

During the year ended December 31, 2014, approximately 66% of the coal CONSOL Energy produced from continued operations was sold under long-term contracts (contracts with terms of one year or more). If a substantial portion of CONSOL Energy's long-term contracts are modified or terminated or if force majeure is exercised, CONSOL Energy would be adversely affected if we are unable to replace the contracts or if new contracts are not at the same level of profitability. If existing customers do not honor current contract commitments, our revenue would be adversely affected. The profitability of our long-term coal supply contracts depends on a variety of factors, which vary from contract to contract and fluctuate during the contract term, including our production costs and other factors. Price changes, if any, provided in long-term supply contracts may not reflect our cost increases, and therefore, increases in our costs may reduce our profit margins. In addition, in periods of declining market prices, provisions in our long-term coal contracts for adjustment or renegotiation of prices and other provisions may increase our exposure to short-term coal price volatility. As a result, CONSOL Energy may not be able to obtain long-term agreements at favorable prices compared to either market conditions, as they may change from time to time, or our cost structure, and long-term contracts may not contribute to our profitability.

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

For the year ended December 31, 2014, we derived over 10% of our total revenues from sales to two coal customers individually and more than 30% of our total revenue from sales to our four largest coal and gas customers. At December 31, 2014, we had approximately 30 coal supply agreements with these customers that expire at various times from 2015 to 2018. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term coal supply agreements. If any one of these customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer.

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

Our ability to receive payment for natural gas and coal sold and delivered depends on the continued creditworthiness of our customers. Some power plant owners may have credit ratings that are below investment grade. If the creditworthiness of our customers declines significantly, our $125 million accounts receivable securitization program and our business could be adversely affected. In addition, if customers refuse to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

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

We gather, process and transport our gas to market by utilizing pipelines and facilities owned by others. If pipeline or facility capacity is limited, or if pipeline or facility capacity is unexpectedly disrupted for any reason, our gas sales and/or sales of natural gas liquids could be limited, reducing our profitability. If we cannot access processing pipeline transportation facilities, we may have to reduce our production of gas. If our sales of gas or natural gas liquids are reduced because of transportation or processing constraints, our revenues will be reduced, and our unit costs will also increase. If pipeline quality standards change, we might be required to install additional processing equipment which could increase our costs. The pipeline could also curtail our flows until the gas delivered to their pipeline is in compliance.

Coal producers depend upon rail, barge, trucking, overland conveyor and other systems to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lock-outs, terrorist attacks or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability.

Transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer's purchasing decision. Increases in transportation costs could make our coal less competitive.

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

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

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

The characteristics of coal may make it costly for electric power generators and other coal users to comply with various environmental standards regarding the emissions of impurities released when coal is burned which could cause utilities to replace coal-fired power plants with alternative fuels. In addition, various incentives have been proposed to encourage the generation of electricity from renewable energy sources. A reduction in the use of coal for electric power generation could decrease the volume of our domestic coal sales and adversely affect our results of operations.

Coal contains impurities, including sulfur, mercury, and other constituents, many of which are released into the air along with fine particulate matter and carbon dioxide when coal is burned. Environmental regulations governing emissions from coal fired electric generating plants could affect demand for coal as a fuel source and affect volume of our sales. Complying with regulations on these emissions can be costly for electric power generators. For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users would either need to install and operate advanced air pollution control equipment, purchase emission allowances, or switch to other fuels. Each option has limitations. Lower sulfur coal may be more costly to purchase on an energy basis than higher sulfur coal depending on mining and transportation costs. Switching to other fuels may require expensive modification of existing plants. Because higher sulfur coal currently accounts for a significant portion of our sales, the extent to which electric power generators switch to alternative fuel could materially affect us. In the last two years the U.S. EPA promulgated or finalized several rulemakings impacting coal generating facilities. These include the Utility Maximum Control Technology (UMACT) rule which includes more stringent emission limits for particulate matter (PM), SO2 and NO_X; and the Mercury and Air Toxics Standards (MATS) rule which set new mercury and air toxic standards. Additionally, litigation staying implementation of EPA's Cross-State Air Pollution Rule (CSAPR) was finalized and the rule went into effect in October 2014 with Phase 1 implementation scheduled for 2015 and Phase 2 beginning in 2017. In late 2014, the EPA also proposed to lower the primary and secondary standard National Ambient Air Quality Standards (NAAQS) for ozone which could have a large impact on the fossil fuel industry.

In December 2014, the EPA resolved the uncertainty that surrounded the future management of coal combustion residuals (CCR), also known as coal ash, produced from the combustion of coal in coal-fired electric generating units and finalized rules requiring the management of CCRs pursuant to the solid waste provisions (Subtitle D) of the Resource Conservation and Recovery Act (RCRA) and not under the hazardous waste provisions (Subtitle C).

Finally, in May 2014, the EPA finalized standards under Section 316(b) of the Clean Water Act (CWA) to reduce the injury and death of fish and other aquatic life caused by cooling-water intake structures at existing power plants, including coal- and natural gas-fired power plants. These national requirements will be implemented through facility permits pursuant to the National Pollutant Discharge Elimination System (NPDES),

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

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

While climate change legislation in the U.S. is unlikely in the next several years, the issue of global climate change continues to attract considerable public and scientific attention with widespread concern about the impacts of human activity, especially the emissions of greenhouse gases (GHGs) such as carbon dioxide and methane. Combustion of fossil fuels, such as the natural gas and coal we produce, results in the creation of carbon dioxide emissions into the atmosphere by natural gas and coal end-users, such as coal-fired electric power generation plants. Numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government that are intended to limit emissions of GHGs. Several states have already adopted measures requiring reduction of GHGs within state boundaries. Other states have elected to participate in voluntary regional cap-and-trade programs like the Regional Greenhouse Gas Initiative (RGGI) in the northeastern U.S. Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (but has not been ratified by the United States, and Canada officially withdrew from its Kyoto commitment in 2012) was nominally extended past its expiration date of December 2012 with a requirement for a new legal construct to be put into place by 2015. The EPA has elected to regulate GHGs under the Clean Air Act.

New rules governing carbon dioxide emissions from fossil fuel powered electric generating plants were proposed in 2013 and 2014, including a New Source Performance Standard (NSPS) for new fossil fuel fired power plants and the Clean Power Plan, respectively, to cut carbon emissions from existing power plants. The EPA estimates that by 2030, the rule will achieve a 30% reduction in CO2 emissions from the U.S. electric power sector from 2005 levels and will reduce coal consumption for electricity generation by about 27% relative to the base case (i.e., relative to what it would be in the absence of the regulation), and will reduce mine-mouth coal prices by about 15% relative to the base case.

Apart from governmental regulation, on February 4, 2008, three of Wall Street’s largest investment banks announced that they had adopted climate change guidelines. The guidelines require the evaluation of carbon risks in the financing of electric power generation plants which may make it more difficult for utilities to obtain financing for coal-fired plants.

Adoption of comprehensive legislation or regulation focusing on GHGs emission reductions for the United States (including the proposed rules discussed above) or other countries where we sell coal, or the inability of utilities to obtain financing in connection with coal-fired plants, may make it more costly to operate fossil fuel fired (especially coal-fired) electric power generation plants and make fossil fuels less attractive for electric utility power plants in the future. Depending on the nature of the regulation or legislation, natural gas-fueled power generation could become more economically attractive than coal-fueled power generation, substantially increasing the demand for natural gas. Apart from actual regulation, uncertainty over the extent of regulation of GHG emissions may inhibit utilities from investing in the building of new coal-fired plants to replace older plants or investing in the upgrading of existing coal-fired plants. Any reduction in the amount of coal or possibly natural gas consumed by domestic electric power generators as a result of actual or potential regulation of greenhouse gas emissions could decrease demand for our fossil fuels, thereby reducing our revenues and materially and adversely affecting our business and results of operations. We or our customers may also have to invest in carbon dioxide capture and storage technologies in order to burn coal or natural gas and comply with future GHG emission standards.

In addition, coalbed methane must be expelled from our underground coal mines for mining safety reasons. Coalbed methane has a greater GHG effect than carbon dioxide. Our natural gas operations capture coalbed methane from our underground coal mines, although some coalbed methane is vented into the atmosphere when the coal is mined. If regulation of GHG emissions does not exempt the release of coalbed methane, we may have to further reduce our methane emissions, pay higher taxes, incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines or perhaps curtail coal production.

Our natural gas and coal mining operations are subject to operating risks, including our reliance upon third party contractors, which could increase our operating expenses and decrease our production levels which could adversely affect our results of operations. Our natural gas and coal 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 exploration for and production of natural gas involves numerous operating risks. The cost of drilling, completing and operating our shale gas wells, shallow oil and gas wells and coalbed methane (CBM) wells is often uncertain, and a number of factors can delay or prevent drilling operations, decrease production and/or increase the cost of our gas operations at particular sites for varying lengths of time thereby adversely affecting our operating results. The operating risks that may have a significant impact on our gas operations include:

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

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.

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 gas or coal operations.

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

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

A decrease in the availability or increase in the costs of commodities or capital equipment used in mining operations could decrease our coal production, impact our cost of coal production and decrease our anticipated profitability.

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

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

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. Delays or denials of gas permits could reduce our production, cash flows and results of operations.

Most coal producers in the eastern U.S. are being impacted by government regulations and enforcement to a much greater extent than a few years ago, particularly in light of the renewed focus by environmental agencies and the government generally on the mining industry, including more stringent enforcement and interpretation of the laws that regulate mining. The pace with which the government issues permits needed for new operations and for on-going operations to continue mining has negatively impacted expected production, especially in Central Appalachia. Environmental groups in Southern West Virginia and Kentucky have challenged state and U.S. Army Corps of Engineers (ACOE) permits for mountaintop and other types of surface mining operations on various grounds. The most recent challenges have focused on the adequacy of the U.S. Army Corps of Engineers analysis of impacts to streams and the adequacy of mitigation plans to compensate for stream impacts resulting from valley fill permits required for mountaintop mining. These challenges have also enhanced the EPA's oversight and involvement in the review of permits by state regulatory authorities. In 2011, the EPA revoked an ACOE-issued Section 404 permit to a mining operator. Following the U.S. Supreme Court’s refusal in March 2012 to hear an appeal from the D.C. Circuit Court’s ruling upholding the EPA’s power to revoke a permit, in September 2014 the U.S. Court of Appeals upheld the EPA’s action to revoke the permit. In addition, in July 2014 the D.C Circuit reversed a lower court’s decision and affirmed the EPA’s authority to adopt the Enhanced Coordination Process governing coordination with the ACOE in the processing of CWA permits. The Court also rejected challenges to EPA’s 2012 “Final Guidance” document regarding appropriate permit conditions, namely those affecting acceptable conductivity limits (e.g., acceptable ionic strength to support aquatic life). However, the Court left it up to the states on whether to adopt the guideline recommendations when issuing final NPDES permits. This decision has left mining permits in some degree of uncertainty whether the EPA will concur with a state’s draft permit conditions should they not contain specified limits regarding conductivity, further increasing operational uncertainty and costs.

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

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local authorities, as well as foreign authorities relating to protection of the environment. These include those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the cleanup of contaminated sites, groundwater quality and availability, threatened and endangered plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, the installation of various safety equipment in our mines, remediation of impacts of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations and competitive position.

In addition, there is the possibility that we could incur substantial costs as a result of violations under environmental laws. Any additional laws, regulations and other legal requirements enacted or adopted by federal, state and local authorities, as well as foreign authorities or new interpretations of existing legal requirements by regulatory bodies relating to the protection of the environment could further affect our costs of operations and competitive position. The Clean Water Act is being used by opponents of mountain top removal mining as a means to challenge permits and bring citizen suits to make coal mining more expensive. At CONSOL Energy’s Fola Mining Operations, six citizen suits have been filed challenging water discharge permits. Two of those suits were settled in 2014, and at least two are potentially affected by recent settlements by another mining operator in a similar case, Existing and future government laws, regulations and other legal requirements relating to protection of the environment, and others that govern our business may increase our costs of doing business for natural gas, and may restrict our gas operations.

Regulations applicable to the gas industry are under constant review for amendment or expansion at the federal and state level. Any future changes may affect, among other things, the pricing or marketing of gas production. For example, hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as Marcellus Shale. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Hydraulic fracturing is currently exempt from regulation under the federal Safe Drinking Water Act, except for hydraulic fracturing using diesel fuel. The disposal of produced water, drilling fluids and other wastes in underground injection disposal wells is regulated by the EPA under the federal Safe Drinking Water Act or by the states under counterpart state laws and regulations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing operations or to dispose of waste resulting from such operations. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities with a final report to be issued in 2015 along with stated accompanying regulation. EPA has also announced it will expand its CAA Subpart W regulations in 2015 to further address GHG and carbon dioxide emissions at wellheads and gathering facilities associated with natural gas production. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy (DOE), the U.S. Government Accountability Office and the Department of the Interior. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances. If hydraulic fracturing is regulated at the federal, state or local 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, air emissions that stem from hydraulic fracturing and completions processes, as well as from midstream activities such as the gathering and transmission of natural gas, are regulated by federal and state rules. However, interpretations of those rules, as well as additional changes to the regulations, could negatively impact our ability to meet our stated production objectives for the company. For example, source aggregation of air emissions to determine whether, under the Clean Air Act a source comprises a single stationary source and is therefore a major source of air pollution, and thereby subject to the applicability of Nonattainment Prevention of Significant Deterioration and Title V permitting requirements, has and continues to be debated by the EPA, state regulatory agencies and the courts. Federal and state activities as well as court decisions could impact the development and transmission of plans of CONSOL, our joint venture partners, and gathering systems being installed and operated by CONE Midstream Partners, LP.

Additionally, some states have begun to adopt more stringent regulation and oversight of natural gas gathering lines than is currently required by federal standards. Pennsylvania, under Act 127, authorized the Public Utility Commission (PUC) oversight of Class I gathering lines, as well as requiring standards and fees associated with Class II and Class III pipelines. The state of Ohio also moved to regulate natural gas gathering lines in a similar manner pursuant to Ohio Senate Bill 315 (SB315). SB315 expanded the Ohio PUC's authority over rural natural gas gathering lines. These changes in interpretation and regulation affect CONSOL Energy's midstream activities, requiring changes in reporting as well as increased costs.

Further, some state and local governments in the Marcellus Shale region in Pennsylvania and New York have considered or imposed a temporary moratorium on drilling operations using hydraulic fracturing until further study of the potential for environmental and human health impacts by the EPA or the relevant agencies are completed. Further, states could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. Also, a few municipalities in Colorado have adopted ordinances to ban hydraulic fracturing. No assurance can be given as to whether or not similar measures might be considered or implemented in jurisdictions in which our gas properties are located. If new laws or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in states in which we operate, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. New laws or regulations could also cause delays or interruptions or terminations of operations, the extent of which cannot be predicted, and could reduce the amount of oil and natural gas that we ultimately are able to produce in commercially paying quantities from our gas properties, all of which could have a materially adverse effect on our results of operations and financial condition.

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

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

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

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

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

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

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

In West Virginia there are areas where drainage from coal mining operations contains concentrations of selenium that without treatment would result in violations of state water quality standards that are set to protect fish and other aquatic life. CONSOL Energy has several operations with selenium discharges. CONSOL Energy and other coal companies have worked to expeditiously develop cost effective means to remove selenium from mine water.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could adversely affect us. An example of this is Naturally Occurring Radioactive Material (NORM) or Technologically-Enhanced, Naturally Occurring Radioactive Material (TENORM). NORM or TENORM is produced when activities such as deep drilling concentrate or expose radioactive materials that occur naturally in ores, soils, water, or other natural materials. State and federal agencies are examining the possibility for worker exposure or associated environmental hazards due to processing and disposal of wastes containing NORM or TENORM. CONSOL Energy's operations could be affected if there is a hazard associated with NORM/TENORM or if it were to be regulated in such a way as to require expensive treatment and disposal options.

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

The Surface Mining Control and Reclamation Act establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Also, state laws require us to plug gas wells and reclaim well sites after the useful life of our gas wells has ended. CONSOL Energy accrues for the costs of current mine disturbance, gas well plugging and of final mine closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing liabilities and gas well plugging, which are based upon permit requirements and our experience, were approximately $576 million at December 31, 2014. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. Furthermore, these obligations are unfunded. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.

Most states where we operate require us to post bonds for the full cost of coal mine reclamation (full cost bonding). West Virginia is not a full cost bonding state. West Virginia has an alternative bond system (ABS) for coal mine reclamation which consists of (i) individual site bonds posted by the permittee that are less than the full estimated reclamation cost plus (ii) a bond pool (Special Reclamation Fund) funded by a per ton fee on coal mined in the State which is used to supplement the site specific bonds if needed in the event of bond forfeiture. The Special Reclamation Fund was underfunded, resulting in a citizen suit before the U.S. District Court in West Virginia. In an effort to settle the issue in 2012, the WV legislature authorized an increase in the per ton fee levied on coal production to make up the shortfall. There remains the possibility that WV may move to full cost bonding in the future which could cause individual mining companies and/or surety companies to exceed bonding capacity and would result in the need to post cash bonds or letters of credit which would reduce operating capital. Pennsylvania is expanding its full cost bonding program to cover all coal mine bonding, further increasing the amount of surety bonds CONSOL Energy must seek in order to permit its mining activities.

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

Natural gas and oil reserves require subjective estimates of underground accumulations of natural gas and oil and assumptions concerning natural gas and oil prices, production levels, reserve estimates and operating and development costs. As a result, estimated quantities of proved natural gas and oil reserves and projections of future production rates and the timing of development expenditures may be incorrect. For example, a significant amount of our proved undeveloped reserves extensions and discoveries during the last three years were due to the addition of wells on our Marcellus Shale acreage more than one offset location away from existing production with reliable technology, which may be more susceptible to positive and negative changes in reserve estimates than our proved developed reserves. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing and production. Also, we make certain assumptions regarding natural gas and oil prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our natural gas reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of natural gas and oil reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas we ultimately recover being different from reserve estimates. The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved natural gas reserves on historical average prices and costs. However, actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

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

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. If natural gas prices decline by $0.10 per Mcf, then the pre-tax present value using a 10% discount rate of our proved natural gas reserves as of December 31, 2014 would decrease from $4.9 billion to $4.7 billion.

Similarly, there are uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include:

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

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

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

Defects may exist in our chain of title for our gas estate and we have not done a thorough chain of title examination of our gas estate. We may incur additional costs and delays to produce gas because we have to acquire additional property rights to perfect our title to gas rights. If we fail to acquire additional property rights to perfect our title to gas rights, we may have to reduce our estimated reserves.

Substantial amounts of acreage in which we believe we control gas rights are in areas where we have not yet done a thorough chain of title examination of the gas estate. A number of our gas properties were acquired primarily for the coal rights with the focus on the coal estate title, and, in many cases were acquired years ago. In addition, we have acquired gas rights in substantial acreage from third parties who had not performed thorough chain of title work on their gas properties. Our practice, and we believe industry practice, is not to perform a thorough title examination on gas properties until shortly before the commencement of drilling activities at which time we seek to acquire any additional rights needed to perfect our ownership of the gas estate for development and production purposes. When we perform a thorough chain of title examination, we may discover material defects in our title which would require us to acquire additional property rights. We may incur substantial costs to acquire these additional property rights. In addition, the acquisition of the necessary rights may not be feasible in some cases. Our discovering of title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves.

Some states (West Virginia and Virginia) permit us to produce coalbed methane gas without perfected ownership under an administrative process known as “pooling,” which requires 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 coalbed methane 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.

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

We are party to a number of legal proceedings in the normal course of business activities. Defending these actions, especially purported class actions, can be costly, and can distract management. For example, we are a defendant in three pending purported class action lawsuits dealing with claimants’ entitlement to, and accounting for, gas royalties. There is the potential that the costs of defending litigation in an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Note 24 - Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion of pending legal proceedings.

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

CONSOL Energy provides various long-term employee benefits to inactive and retired employees. We accrue amounts for these obligations. At December 31, 2014, the current and non-current portions of these obligations included:

- postretirement medical and life insurance ($761 million);
- coal workers' black lung benefits ($126 million);
- salaried retirement benefits ($119 million); and
- workers' compensation ($90 million).

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

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

CONSOL Energy's defined benefit pension plan for salaried employees allows such employees to receive a lump-sum distribution for benefits earned up through December 31, 2005 in lieu of annual payments when they retire from CONSOL Energy. Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans for Terminations Benefits requires that if the lump-sum distributions made for a plan year exceed the total of the service cost and interest cost for the plan year, CONSOL Energy would need to recognize for that year's results of operations an adjustment equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum in that year. If the settlement is triggered in future periods, it may be material to operating results.

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

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

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

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

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

In the second half of 2011, we, through our principal gas operations subsidiary, CNX Gas, entered into joint venture arrangements with Noble Energy, Inc. and with a subsidiary of Hess Corporation, regarding our shale gas assets. We sold a 50% undivided interest in certain of our Marcellus shale oil and natural gas assets to Noble Energy and a 50% undivided interest in certain of our Utica shale acres in Ohio to Hess. The following aspects of these joint ventures could materially impact us:

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

Each joint development agreement assigns to each party designated areas over which that party will manage and control operations. We could incur liability as a result of action taken by one of our joint venture partners.

One of the potential benefits of these two joint ventures is the obligation of the other party to pay a portion of our share of drilling and development costs for new wells, which we called "carried costs." At December 31, 2014, the remaining carried costs obligation of Noble Energy was approximately $1.63 billion while Hess' remaining carried costs obligation was approximately $99 million. Thus, the benefits we anticipate receiving in the joint ventures depend in part upon the rate at which new wells are drilled and developed in each joint venture, which could fluctuate significantly from period to period. Moreover, the performance of these third party obligations is outside our control. The inability or failure of our joint venture partners to pay their portion of development costs, including our carried costs during the carry period, could increase our costs of operations or result in reduced drilling and production of oil and natural gas or loss of rights to develop the oil and natural gas properties held by that joint venture.

Noble Energy's obligation to pay carried costs is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per million British thermal units or “MMbtu” in any three consecutive month period and will remain suspended until average natural gas prices are above $4.00/MMbtu for three consecutive months. As a result of this provision, Noble Energy's obligation to pay carried costs was suspended from December 1, 2011 to March 1, 2014 and was again suspended on November 1, 2014. We cannot predict when this latest suspension will be lifted and Noble Energy's obligation to pay the carried costs will resume. This suspension has the effect of requiring us to incur our entire 50 percent share of the drilling and completion costs for new wells during the suspension period and delaying receipt of a portion of the value we expect to receive in the transaction.

The Hess joint development agreement provides that any transfer of interest in the joint venture by us or Hess will be subject to a right of first offer in favor of the other party. These restrictions may preclude transactions which could be beneficial to our shareholders.

Disputes between us and our joint venture partners may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

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

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

As of December 31, 2014, our total indebtedness was approximately $3.29 billion of which approximately $1.85 billion was under our 5.875% senior unsecured notes due 2022 plus $7 million of unamortized bond premium, $1.02 billion was under our 8.250% senior unsecured notes due 2020, $250 million was under our 6.375% senior notes due 2021, $103 million was under our Maryland Economic Development Corporation Port Facilities Refunding Revenue Bonds (MEDCO) 5.75% revenue bonds due September 2025, $47 million of capitalized leases due through 2021, and $17 million of miscellaneous debt. The degree to which we are leveraged could have important consequences, including, but not limited to:

- increasing our vulnerability to general adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to the payment of interest and principal due under our outstanding debt, which will limit our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, development of our gas and coal reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal and gas industries;
- placing us at a competitive disadvantage compared to our competitors with lower leverage and better access to capital resources; and
- limiting our ability to implement our business strategy, including the structuring and formation of a master limited partnership for our thermal coal business and a subsidiary entity for the purpose of owning the metallurgical coal properties and related mining operations.

Our senior secured credit facility and the indentures governing our 5.875%, 8.250% and 6.375% senior unsecured notes limit the incurrence of additional indebtedness unless specified tests or exceptions are met. In addition, our senior secured credit agreement and the indentures governing our 5.875%, 8.250% and 6.375% senior unsecured notes subject us to financial and/or other restrictive covenants. Under our senior secured credit agreement, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio, and a minimum current ratio, as defined therein. Our senior secured credit agreement and the indentures governing our 5.875%, 8.250% and 6.375% senior unsecured notes impose a number of restrictions upon us, such as restrictions on granting liens on our assets, making investments, paying dividends, stock repurchases, selling assets and engaging in acquisitions. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have an adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our senior secured credit agreement and the indentures governing our 5.875%, 8.250% and 6.375% senior unsecured notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

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

Producing natural gas and oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2014, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs

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

To manage our exposure to fluctuations in the price of natural gas, we enter into hedging arrangements with respect to a portion of our expected production. As of January 15, 2015, we had hedges on approximately 121.2 Bcf of our 2015 natural ga