VECTREN CORP
Form 10-Q
May 02, 2013

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2013

OR

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

For the transition period from __________________ to __________________

Commission file number: 1-15467

VECTREN CORPORATION
(Exact name of registrant as specified in its charter)

INDIANA	35-2086905
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

One Vectren Square, Evansville, IN 47708
(Address of principal executive offices)
(Zip Code)

812-491-4000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
ý Yes ¨ No

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

Large accelerated filer ý Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company) Smaller reporting company ¨

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

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

Common Stock- Without Par Value	82,273,816	April 30, 2013
Class	Number of Shares	Date

Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports free of charge through its website at www.vectren.com as soon as reasonably practicable after electronically filing or furnishing the reports to the SEC, or by request, directed to Investor Relations at the mailing address, phone number, or email address that follows:

Mailing Address:	Phone Number:	Investor Relations Contact:
One Vectren Square	(812) 491-4000	Robert L. Goocher
Evansville, Indiana 47708		Treasurer and Vice President, Investor Relations
		rgoocher@vectren.com

Definitions

BCF: billions of cubic feet

BTU: British thermal units

EPA: Environmental Protection Agency

FAC: Fuel Adjustment Clause

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

GAAP: Generally Accepted Accounting Principles

IDEM: Indiana Department of Environmental Management

IURC: Indiana Utility Regulatory Commission

MISO: Midcontinent Independent System Operator (formerly Midwest Independent System Operator)

MSHA: Mine Safety and Health Administration

MW: megawatts

MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)

OUCC: Indiana Office of the Utility Consumer Counselor

PUCO: Public Utilities Commission of Ohio

Throughput: combined gas sales and gas transportation volumes

XBRL: eXtensible Business Reporting Language

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited – In millions)

	March 31, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash & cash equivalents	$12.1	$19.5
Accounts receivable - less reserves of $7.3 & $6.8, respectively	300.0	216.7
Accrued unbilled revenues	129.8	185.0
Inventories	123.5	158.6
Recoverable fuel & natural gas costs	10.2	25.3
Prepayments & other current assets	42.1	73.3
Total current assets	617.7	678.4
Utility Plant		
Original cost	5,225.0	5,176.8
Less: accumulated depreciation & amortization	2,086.3	2,057.2
Net utility plant	3,138.7	3,119.6
Investments in unconsolidated affiliates	71.8	78.1
Other utility & corporate investments	35.0	34.6
Other nonutility investments	25.2	24.9
Nonutility plant - net	608.1	598.0
Goodwill - net	262.3	262.3
Regulatory assets	244.2	252.7
Other assets	37.8	40.5
TOTAL ASSETS	$5,040.8	$5,089.1

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

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VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited – In millions)

	March 31, 2013	December 31, 2012
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$158.3	$180.6
Accounts payable to affiliated companies	41.0	29.7
Accrued liabilities	195.1	198.8
Short-term borrowings	193.6	278.8
Current maturities of long-term debt	257.6	106.4
Total current liabilities	845.6	794.3
Long-term Debt - Net of Current Maturities	1,401.9	1,553.4
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	654.5	637.2
Regulatory liabilities	370.2	364.2
Deferred credits & other liabilities	219.4	213.9
Total deferred credits & other liabilities	1,244.1	1,215.3
Commitments & Contingencies (Notes 7, 9-11)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 82.3 & 82.2 shares, respectively	703.0	700.5
Retained earnings	850.4	829.9
Accumulated other comprehensive (loss)	(4.2)	(4.3)
Total common shareholders' equity	1,549.2	1,526.1
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$5,040.8	$5,089.1

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED STATEMENTS OF INCOME
(Unaudited – in millions, except per share amounts)

	Three Months Ended March 31, 2013	2012
OPERATING REVENUES		
Gas utility	$315.9	$292.3
Electric utility	149.5	139.4
Nonutility	235.2	172.9
Total operating revenues	700.6	604.6
OPERATING EXPENSES		
Cost of gas sold	157.2	137.1
Cost of fuel & purchased power	50.2	44.7
Cost of nonutility revenues	86.4	59.5
Other operating	215.6	173.2
Depreciation & amortization	66.2	63.6
Taxes other than income taxes	18.2	16.6
Total operating expenses	593.8	494.7
OPERATING INCOME	106.8	109.9
OTHER INCOME (EXPENSE)		
Equity in (losses) of unconsolidated affiliates	(6.7)	(7.6)
Other income – net	2.9	3.3
Total other income (expense)	(3.8)	(4.3)
INTEREST EXPENSE	23.5	24.0
INCOME BEFORE INCOME TAXES	79.5	81.6
INCOME TAXES	29.7	30.3
NET INCOME	$49.8	$51.3
AVERAGE COMMON SHARES OUTSTANDING	82.2	82.0
DILUTED COMMON SHARES OUTSTANDING	82.3	82.0
EARNINGS PER SHARE OF COMMON STOCK:		
BASIC	$0.61	$0.63
DILUTED	$0.61	$0.62
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.355	$0.350

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

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VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited – in millions)

	Three Months Ended March 31,	
	2013	2012
Net income	$49.8	$51.3
Accumulated other comprehensive income (AOCI) of unconsolidated affiliates		
Net amount arising during the year before tax	0.2	2.9
Income taxes related to items of other comprehensive income	(0.1)	(1.3)
AOCI of unconsolidated affiliates, net of tax	0.1	1.6
Total comprehensive income	$49.9	$52.9

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited – In millions)

	Three Months Ended March 31, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$49.8	$51.3
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	66.2	63.6
Deferred income taxes & investment tax credits	14.2	13.7
Equity in losses of unconsolidated affiliates	6.7	7.6
Provision for uncollectible accounts	2.4	2.3
Expense portion of pension & postretirement benefit cost	2.2	2.7
Other non-cash charges - net	3.5	1.9
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	(30.5)	58.1
Inventories	35.1	4.7
Recoverable/refundable fuel & natural gas costs	15.1	5.5
Prepayments & other current assets	31.3	30.4
Accounts payable, including to affiliated companies	(16.2)	(66.1)
Accrued liabilities	3.0	2.4
Unconsolidated affiliate dividends	0.2	—
Employer contributions to pension & postretirement plans	(3.4)	(4.9)
Changes in noncurrent assets	4.8	0.8
Changes in noncurrent liabilities	1.1	(5.2)
Net cash flows from operating activities	185.5	168.8
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	—	99.5
Dividend reinvestment plan & other common stock issuances	2.3	1.6
Requirements for:		
Dividends on common stock	(29.2)	(28.7)
Retirement of long-term debt	(0.4)	(1.5)
Net change in short-term borrowings	(85.2)	(152.4)
Net cash flows from financing activities	(112.5)	(81.5)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from investing activities	0.3	5.5
Requirements for:		
Capital expenditures, excluding AFUDC equity	(80.4)	(87.2)
Other investments	(0.3)	—
Net cash flows from investing activities	(80.4)	(81.7)
Net change in cash & cash equivalents	(7.4)	5.6
Cash & cash equivalents at beginning of period	19.5	8.6
Cash & cash equivalents at end of period	$12.1	$14.2

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO THE CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
(UNAUDITED)

1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 575,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 314,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining owns coal mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and a leveraged lease, among other investments. All of the above are collectively referred to as the Nonutility Group. Pursuant to service contracts, the Nonutility Group provides the Company's regulated utilities natural gas supply services, coal, and infrastructure services.

2. Basis of Presentation

The interim consolidated condensed financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These consolidated condensed financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2012, filed with the Securities and Exchange Commission on February 15, 2013, on Form 10-K. Because of the seasonal nature of the Company's operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

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3. Earnings Per Share

The Company uses the two class method to calculate earnings per share (EPS). The two class method is an earnings allocation formula that treats a participating security as having rights to earnings that otherwise would have been available to common shareholders. The Company issues a minor amount of performance based awards that participate in dividends and are paid in shares. Under the two class method, earnings for a period are allocated between common shareholders and participating security holders based on their respective rights to receive dividends as if all undistributed book earnings for the period were distributed. Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of stock options and other equity based instruments to the extent the effect is dilutive. The following table illustrates the basic and dilutive EPS calculations for the periods presented in these financial statements.

	Three Months Ended March 31,	
(In millions, except per share data)	2013	2012
Numerator:		
Reported net income (Numerator for Basic and Diluted EPS)	$49.8	$51.3
Denominator:		
Weighted average common shares outstanding (Denominator for Basic EPS)	$82.2	$82.0
Conversion of share based compensation arrangements	0.1	—
Adjusted weighted average shares outstanding and assumed conversions outstanding (Denominator for Diluted EPS)	$82.3	$82.0
Basic EPS	$0.61	$0.63
Diluted EPS	$0.61	$0.62

For the three months ended March 31, 2013 and 2012, all options were dilutive.

4. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received, which totaled $10.7 million and $9.3 million in the three months ended March 31, 2013 and 2012, respectively, as a component of operating revenues. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Retirement Plans & Other Postretirement Benefits

The Company maintains three qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP plan are aggregated under the heading “Pension Benefits.” The postretirement benefit plan is presented under the heading “Other Benefits.”

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost follows and the amortizations shown below are primarily reflected in Regulatory assets as a majority of pension and other postretirement benefits are being recovered through rates.

	Three Months Ended March 31,			
	Pension Benefits		Other Benefits	
(In millions)	2013	2012	2013	2012
Service cost	$2.1	$1.9	$0.1	$0.1
Interest cost	3.7	3.9	0.5	0.9
Expected return on plan assets	(5.5)	(5.3)	—	—
Amortization of prior service cost	0.4	0.4	(0.8)	(0.2)
Amortization of transitional obligation	—	—	—	0.3
Amortization of actuarial loss	2.5	1.7	0.2	0.1
Net periodic benefit cost	$3.2	$2.6	$—	$1.2

Employer Contributions to Qualified Pension Plans

Currently, the Company expects to contribute approximately $10.0 million to its pension plan trusts for 2013. During the three months ended March 31, 2013, contributions of $2.5 million have been made.

6. Supplemental Cash Flow Information

As of March 31, 2013 and December 31, 2012, the Company has accruals related to utility and nonutility plant purchases totaling approximately $10.1 million and $11.1 million, respectively.

7. ProLiance Holdings, LLC

ProLiance Holdings, LLC (ProLiance), a nonutility energy marketing affiliate of Vectren and Citizens Energy Group (Citizens), provides services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance's customers include, among others, Vectren's Indiana utilities as well as Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. Consistent with its ownership percentage, Vectren is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

Summarized Financial Information

	Three Months Ended March 31,	
(In millions)	2013	2012
Summarized statement of income information:		
Revenues	$308.2	$352.7
Operating (loss)	(8.8)	(10.9)
ProLiance's net (loss)	(9.8)	(12.4)

(In millions)	As of March 31, 2013	December 31, 2012
Summarized balance sheet information:		
Current assets	$209.4	$279.7
Noncurrent assets	55.5	55.6
Current liabilities	154.7	215.1
Noncurrent liabilities	0.3	0.3
Members' equity	114.5	124.3
Accumulated other comprehensive (loss)	(7.3)	(7.5)
Noncontrolling interest	2.7	3.1

Vectren records its 61 percent share of ProLiance's results in Equity in (losses) of unconsolidated affiliates. Interest expense and income taxes associated with the investment are recorded separately within the statements of income in those line items. As of March 31, 2013 and December 31, 2012, the Company's investment balance, inclusive of its share of ProLiance's accumulated other comprehensive loss and certain historical book basis differences, is $68.1 million and $73.9 million, respectively. The amounts recorded to Equity in (losses) of unconsolidated affiliates related to ProLiance's operations totaled a pre-tax loss of $6.0 million and $7.6 million for the three months ended March 31, 2013 and 2012, respectively.

Analysis and evaluation of strategic alternatives related to the Company's investment in its energy marketing affiliate, ProLiance Holdings, continues. The Company believes the carrying value of its investment in ProLiance Holdings at March 31, 2013 is appropriate, but if the Company proceeds with one of the strategic alternatives being evaluated, which could include a disposition of its investment in ProLiance Holdings or a disposition by ProLiance Holdings of one or more of its operating subsidiaries or their assets, the amount realized could be materially below the carrying value of the Company's investment.

Investment in Liberty Gas Storage

Liberty Gas Storage, LLC (Liberty), a joint venture between a subsidiary of ProLiance and a subsidiary of Sempra Energy (SE), is a development project for salt-cavern natural gas storage facilities. ProLiance is the minority member with a 25 percent interest, which it accounts for using the equity method. The project was expected to include 17 Bcf of capacity in its North site, and an additional capacity of at least 17 Bcf at the South site. The South site also has the potential for further expansion. The Liberty pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and will connect area LNG regasification terminals to an interstate natural gas transmission system and storage facilities.

In late 2008, the project at the North site was halted due to subsurface and well-completion problems, which resulted in Liberty recording a $132 million impairment charge. The Company, through ProLiance, recorded its share of the charge in 2009. As a result of the issues encountered at the North site, Liberty requested and the FERC approved the separation of the North site from the South site. Approximately 12 Bcf of the storage at the South site, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to connect the caverns to the pipeline system. As of March 31, 2013 and December 31, 2012, ProLiance's investment in Liberty was $35.6 million and $35.5 million, respectively.

Liberty received a demand for Arbitration from Williams Midstream Natural Gas Liquids, Inc. ("Williams") on February 8, 2011 related to a Sublease Agreement ("Sublease") between Liberty and Williams at the North site. Williams alleges that Liberty was negligent in its attempt to convert certain salt caverns to natural gas storage and thereby damaged the caverns. Williams alleges damages of $56.7 million. Liberty believes that it has complied with all of its obligations to Williams, including properly terminating the Sublease. Liberty intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of March 31, 2013, ProLiance has no material reserve recorded related to this matter and this litigation has not materially impacted ProLiance's results of operations or statement of financial position.

Transactions with ProLiance
Purchases of natural gas from ProLiance for resale and for injections into storage for the three months ended March 31, 2013 and 2012 totaled $107.6 million and $79.5 million, respectively. Amounts owed to ProLiance at March 31, 2013 and December 31, 2012, for those purchases were $41.0 million and $29.7 million, respectively, and are included in Accounts payable to affiliated companies in the Consolidated Condensed Balance Sheets. Vectren received regulatory approval on March 17, 2011, from the IURC for ProLiance to continue to provide natural gas supply services to the Company’s Indiana utilities and Citizens Energy Group's utilities through March 2016. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

8. Financing Activities

SIGECO 2013 Debt Refund and Reissuance
In April 2013, approximately $89 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. In May 2013, an additional $22 million of SIGECO's tax-exempt long-term debt will be redeemed at par plus accrued interest pursuant to notice provided to the holders thereof. In April 2013, $111 million of new SIGECO tax-exempt debt was issued to refund this debt. Approximately $62 million of this debt was issued at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043. The remaining $49 million of the called debt will be held by Utility Holdings and will be remarketed at a future date. As of March 31, 2013, the $111 million of SIGECO tax-exempt debt remained classified as long-term.

Utility Holdings Debt Transactions
On April 1, 2013, the Company executed an early redemption at par of $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt will be refinanced with proceeds from a private placement note purchase agreement with a delayed draw feature entered into on December 20, 2012, by Utility Holdings and institutional investors. It provides for the following tranches of notes: (i) $45 million 3.2 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million 4.25 percent senior guaranteed notes, due June 5, 2043. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. Subject to the satisfaction of customary conditions precedent, this financing is scheduled to close on or about June 5, 2013. As of March 31, 2013, the $121.6 million was classified as Current maturities of long-term debt.

9. Commitments & Contingencies

Corporate Guarantees
The Company issues parent level guarantees to certain vendors and customers of its wholly-owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At March 31, 2013, parent level guarantees support a maximum of $25 million of ESG’s performance contracting commitments and warranty obligations and $45 million of other project guarantees. The broader scope of ESG’s performance contracting obligations, including those not guaranteed by the parent company, are described below. In addition, the parent company has approximately $22 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $16 million represent letters of credit supporting other nonutility operations. Guarantees issued and outstanding on behalf of unconsolidated affiliates approximated $3 million at March 31, 2013. These guarantees relate primarily to arrangements between ProLiance and various natural gas pipeline operators. The Company has not been called upon to satisfy any obligations pursuant to these parental guarantees and has accrued no significant liabilities related to these guarantees.

Performance Guarantees & Product Warranties

In the normal course of business, wholly-owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized for the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at March 31, 2013, there are 53 open surety bonds supporting future performance. The average face amount of these obligations is $5.8 million, and the largest obligation has a face amount of $57.3 million. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At March 31, 2013, approximately 54 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years. The Company has no significant accruals for these warranty obligations as of March 31, 2013. In addition, ESG has an $8 million stand-alone letter of credit facility and as of March 31, 2013, $3.4 million was outstanding.

Legal & Regulatory Proceedings

The Company is party to various legal proceedings, audits, and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations or cash flows.

10. Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

Vectren monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. Vectren's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and operational improvement. In 2011, laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects, and in Ohio other capital investment projects, outside of a base rate proceeding. Utilization of these recovery mechanisms is discussed below.

Ohio Recovery and Deferral Mechanisms

The PUCO order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post in service carrying costs is also allowed until the related capital expenditures are recovered through the DRR. The order also established a prospective bill impact evaluation on the annual deferrals, limiting the deferrals at a level which would equal a change over the prior year rate of $1.00 per residential and general service customer per month. To date, the Company has made capital investments under this rider totaling $85 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $7.2 million and $6.5 million at March 31, 2013 and December 31, 2012, respectively. The DRR's initial five year term expires in early 2014. The Company will make a filing in May 2013 proposing to extend the term of the DRR.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. Once such application is approved, the legislation authorizes a deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law. The order provided for the deferral of depreciation, debt-related post in service carrying costs, and property taxes for its $23.5 million capital expenditure program covering the fifteen month period ending December

31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. The Company will file annually for the accounting treatment described above for its annual capital expenditure program.

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Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received orders in 2008 and 2007 associated with the most recent base rate cases. These orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Vectren North and $3 million annually at Vectren South. The debt-related post in service carrying costs are recognized in the Consolidated Statements of Income currently. Such deferral is limited by individual qualifying project to three years after being placed into service at Vectren South and four years after being placed into service at Vectren North.

In April 2011, Senate Bill 251 was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs are to be deferred for future recovery in the utility's next general rate case. To date, the Company has not initiated a filing requesting authority to recover costs using the Senate Bill 251 approach and continues to study its applicability to expenditures associated with its natural gas distribution operations.

Pipeline Safety Law

On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years Those regulations may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the law is expected to result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses. Operating expenses associated with expanded compliance requirements may grow by approximately $9 million annually, with $6 million attributable to the Indiana operations. Related to the Indiana operations, the Company expects to seek recovery under Senate Bill 251, or such costs may be recoverable through current tracking mechanisms. Capital investments, associated with the Pipeline Safety Law, are expected to be significant. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 or other currently authorized recovery mechanisms, such as the Distribution Replacement Rider, in Ohio.

Indiana Senate Bill 560

In April 2013, Senate Bill 560 was signed into law. This legislation, which supplements Senate Bill 251 described above which addressed federally-mandated investment, provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent. The new law also provides for the use of test years in base rate cases that can include twelve month future periods beginning up to 24 months beyond the petition date. To the extent new rates are not approved within 300 days of filing the case-in-chief, or in limited cases within 360 days, 50 percent of the proposed rate increase may be implemented, subject to refund. The Company is currently evaluating the impact that these legislative actions, both Senate Bill 251 and 560, may have on its operations in future periods.

Vectren North Pipeline Safety Investigation
On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. The Company seeks further clarity on the scope of the requirement and the ability to also use contractors to perform certain inspections. Testimony was filed by the Company in April 2013, with subsequent filings by the other parties scheduled for May 2013. A hearing has been scheduled for July 2013 and an order is expected in 2013.

11. Environmental Matters

Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting Vectren South's electric operations. The Company is currently evaluating the impact Senate Bill 251 may have on its operations, including applicability to the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality
Clean Air Interstate Rule / Cross-State Air Pollution Rule
In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO_2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO_2 and NOx allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSAPR set individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances to generating units through state implementation plans, CSAPR allowances were allocated to individual units directly through the federal rule. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. Multiple administrative and judicial challenges were filed. On December 30, 2011, the Court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the Court vacated CSAPR and directed the EPA to continue to administer CAIR. In October 2012, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. EPA's request for rehearing was denied by the Court on January 24, 2013. In March 2013, the EPA filed a petition for review with the US Supreme Court. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air Regulations").

Mercury and Air Toxics (MATS) Rule
On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule is the EPA's response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR's implementation by the Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA agreed to reconsider MATS requirements for new construction. Such requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS

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could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013.

Conclusions Regarding Air Regulations
To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO_2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the 2015 requirement imposed by CAIR, and the NOV discussed above. Due to the correlation amongst the various requirements set forth, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required and could be significant depending on the required method of compliance with the requirements. While the Company has not yet quantified what the additional costs may be associated with these efforts, because the compliance is required by government regulation the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above.

Information Request
SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the information request.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation,

but if finalized, the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2013. Depending on the final rule and on the Company's facts and circumstances, capital investments could approximate $40 million if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 and the Company is reviewing the proposal. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recovered under Senate Bill 251 referenced above.

Coal Ash Waste Disposal & Ash Ponds

In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules have not been finalized given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company's ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as$30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recovered under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. EPA's PSD and Title V permitting rules for GHG's were recently upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards for greenhouse gases for new electric generating facilities under Clean Air Act Section 111(b). EPA missed its deadline for finalization of the new source rule in April, and has indicated that it will finalize the new source rule within the next 18 months. Upon finalization of the new source rule, the EPA intends to propose New Source Performance Standards for greenhouse gases for existing electric generating units under Section 111(d), which would be applicable to the Company's existing units. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown
If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other greenhouse gases or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company’s fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects

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associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. The financial incentives include an enhanced return on equity and tracking mechanisms to recover program costs. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2009, the Company also executed a long term purchase power commitment for 50 MW of wind energy. These transactions supplement a 30 MW wind energy purchase power agreement executed in 2008. Before the impacts of efficiency measures which are defined as clean energy in the legislation, the Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. The Company continues to evaluate whether to participate in this voluntary program.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/feasibility study (RI/FS) was completed at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO’s service territory, all of which are currently enrolled in the IDEM’s VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $42.4 million ($23.2 million at Indiana Gas and $19.2 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.2 million of the expected $15.5 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of March 31, 2013 and December 31, 2012, approximately $5.2 million and $4.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

12. Impact of Recently Issued Accounting Principles

Offsetting Assets and Liabilities
In January 2013, the FASB issued new accounting guidance on disclosures of offsetting assets and liabilities. This guidance amends prior requirements to add clarification to the scope of the offsetting disclosures. The amendment clarifies that the scope applies to derivative instruments accounted for in accordance with reporting topics on derivatives and hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with US GAAP or subject to an enforceable master netting arrangement or similar agreement. This guidance is effective for fiscal years beginning on or after January 1, 2013 and interim periods within annual periods. The Company adopted this guidance as of January 1, 2013. The adoption of this guidance did not have a material impact on the Company's financial statements.

Accumulated Other Comprehensive Income (AOCI)
In February 2013, the FASB issued new accounting guidance on the reporting of reclassifications from AOCI. The guidance requires an entity to report the effect of significant reclassification from AOCI on the respective line items in net income if the amount being reclassified is required under US GAAP to be reclassified in its entirety to net income. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference to other disclosures required that provide additional details about these amounts. The new guidance is effective for fiscal years, and interim periods within annual periods, beginning after December 15, 2012. The Company adopted this guidance as of January 1, 2013. The adoption of this guidance did not have a material impact on the Company's financial statements.

13. Fair Value Measurements

The carrying values and estimated fair values using primarily Level 2 assumptions of the Company's other financial instruments follow:

	March 31, 2013		December 31, 2012	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,659.5	$1,863.3	$1,659.8	$1,873.3
Short-term borrowings	193.6	193.6	278.8	278.8
Cash & cash equivalents	12.1	12.1	19.5	19.5

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities marked to fair value.

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's long-term debt was estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for instruments with similar characteristics. Because of the maturity dates and variable interest rates of short-term borrowings and cash & cash equivalents, those carrying amounts approximate fair value. Because of the inherent difficulty of estimating interest rate and other market risks, the methods used to estimate fair value may not always be indicative of actual realizable value, and different methodologies could produce different fair value estimates at the reporting date.

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue or over a 15-year period. Accordingly, any reacquisition of this debt would not be expected to have a material effect on the Company's results of operations.

Because of the customized nature of notes receivable investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At March 31, 2013 and December 31, 2012, the fair value for these financial instruments was not estimated. The carrying value of these investments was approximately $2.3 million at March 31, 2013 and $2.1 million at December 31, 2012.

14. Segment Reporting

The Company segregates its operations into three groups: 1) Utility Group, 2) Nonutility Group, and 3) Corporate and Other.

The Utility Group is comprised of Vectren Utility Holdings, Inc.'s operations, which consist of the Company's regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between Gas Utility Services and Electric Utility Services. Gas Utility Services provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west-central Ohio. Electric Utility Services provides electric distribution services to southwestern Indiana, and includes the Company's power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Utility Group reports three segments: Gas Utility Services, Electric Utility Services, and Other operations.

The Nonutility Group reports five segments: Infrastructure Services, Energy Services, Coal Mining, Energy Marketing, and Other Businesses.

Corporate and Other includes unallocated corporate expenses such as advertising and charitable contributions, among other activities, that benefit the Company's other operations. Net income is the measure of profitability used by management for all operations. Information related to the Company's reportable segments is summarized as follows:

	Three Months Ended March 31,	
(In millions)	2013	2012
Revenues		
Utility Group		
Gas Utility Services	$315.9	$292.3
Electric Utility Services	149.5	139.4
Other Operations	9.5	9.9
Eliminations	(9.4)	(9.5)
Total Utility Group	465.5	432.1
Nonutility Group		
Infrastructure Services	171.8	117.5
Energy Services	20.5	22.2
Coal Mining	63.1	58.5
Other Businesses	—	0.1
Total Nonutility Group	255.4	198.3
Eliminations	(20.3)	(25.8)
Consolidated Revenues	$700.6	$604.6
Profitability Measure - Net Income		
Utility Group		
Gas Utility Services	$38.1	$37.5
Electric Utility Services	14.6	15.6
Other Operations	2.4	2.9
Utility Group Net Income	55.1	56.0
Nonutility Group Net Income (Loss)		
Infrastructure Services	6.9	3.0
Energy Services	(1.4)	(1.7)
Coal Mining	(6.0)	(0.3)
Energy Marketing	(4.6)	(5.9)

Other Businesses	(0.3)	0.1
Nonutility Group Net Income (Loss)	(5.4)	(4.8)
Corporate & Other Group Net Income	0.1	0.1
Consolidated Net Income	$49.8	$51.3

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

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also earns a return on shared assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 575,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 314,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services.

Executive Summary of Consolidated Results of Operations

In this discussion and analysis, the Company analyzes contributions to consolidated earnings and earnings per share from its Utility Group and Nonutility Group separately since each operates independently requiring distinct competencies and business strategies, offers different energy and energy related products and services, and experiences different opportunities and risks.

The Utility Group generates revenue primarily from the delivery of natural gas and electric service to its customers. The primary source of cash flow for the Utility Group results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services. The activities of, and revenues and cash flows generated by, the Nonutility Group are closely linked to the utility industry, and the results of those operations are generally impacted by factors similar to those impacting the overall utility industry. In addition, there are other operations, referred to herein as Corporate and Other, that include unallocated corporate expenses such as advertising and charitable contributions, among other activities.

The Company has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company's SEC filings. The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company's 2012 annual report filed on Form 10-K.

Net income and earnings per share, in total and by group, for the three months ended March 31, 2013 and 2012 follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2013	2012
Net income (loss)	$49.8	$51.3
Attributed to:		
Utility Group	55.1	56.0
Nonutility Group	(5.4)	(4.8)
Corporate & other	0.1	0.1
Basic EPS	$0.61	$0.63
Attributed to:		
Utility Group	0.67	0.69
Nonutility Group	(0.06)	(0.06)
Corporate & other	—	—

Utility Group

In 2013, the Utility Group's first quarter earnings were $55.1 million, compared to $56.0 million in 2012. The modest quarter over quarter decrease is primarily the result of the unfavorable timing of operating expenses, which was partially offset by the impacts of favorable first quarter weather compared to the prior year.

Gas Utility Services

Gas Utility Services earned $38.1 million during the three months ended March 31, 2013, compared to earnings of $37.5 million in the first quarter of 2012. Results in 2013 have been impacted by small customer growth and increased large customer margin, which was offset by the timing of operating expenses. Year-over-year results continue to be favorably impacted by returns earned on increased investment in bare steel and cast iron pipe replacements, particularly in Ohio.

Electric Utility Services

The Electric Utility Services first quarter 2013 earnings were $14.6 million, compared to $15.6 million in the first quarter of 2012. Management estimates the impact of weather on retail electric margin, compared to normal temperatures, to be approximately $0.3 million favorable in the first quarter of 2013. This compares to the first quarter of 2012 where management estimated a $3.6 million unfavorable impact on margin compared to normal. The increased earnings were more than offset by lower small customer margin resulting from conservation initiatives, net of lost margin recovery, and increased operating expenses primarily associated with generation related variable production costs.

Other Utility Operations

Year to date in 2013, earnings from other utility operations were $2.4 million, compared to $2.9 million in 2012.

Nonutility Group

In the first quarter of 2013, Nonutility Group results decreased $0.6 million, compared to the first quarter of 2012. Results in 2013 reflect increased Infrastructure Services results of $3.9 million quarter over quarter, primarily due to increased demand for services. Results at ProLiance improved quarter over quarter by $1.3 million primarily due to lower demand charges compared to the prior year. Coal Mining results declined $5.7 million in the first quarter of 2013, compared to 2012, more than offsetting the improved earnings at Infrastructure Services and ProLiance. Coal Mining's decreased results are primarily due to the continued softness in the overall coal market and continued difficult mining conditions at the Prosperity mine.

Dividends

Dividends declared for the three months ended March 31, 2013, were $0.355 per share, compared to $0.350 per share for the same period in 2012.

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Use of Non-GAAP Performance Measures and Per Share Measures

Per share earnings contributions of the Utility Group, Nonutility Group, and Corporate and Other are presented and are non-GAAP measures. Such per share amounts are based on the earnings contribution of each group included in Vectren's consolidated results divided by Vectren's basic average shares outstanding during the period. The earnings per share of the groups do not represent a direct legal interest in the assets and liabilities allocated to the groups, but rather represent a direct equity interest in Vectren Corporation's assets and liabilities as a whole. These non-GAAP measures are used by management to evaluate the performance of individual businesses. In addition, other items giving rise to period over period variances, such as weather, may be presented on an after tax and per share basis. These amounts are calculated at a statutory tax rate divided by Vectren's basic average shares outstanding during the period. Accordingly, management believes these measures are useful to investors in understanding each business' contribution to consolidated earnings per share and in analyzing consolidated period to period changes and the potential for earnings per share contributions in future periods. Reconciliations of the non-GAAP measures to their most closely related GAAP measure of consolidated earnings per share are included throughout this discussion and analysis. The non-GAAP financial measures disclosed by the Company should not be considered a substitute for, or superior to, financial measures calculated in accordance with GAAP, and the financial results calculated in accordance with GAAP.

Detailed Discussion of Results of Operations

Following is a more detailed discussion of the results of operations of the Company's Utility and Nonutility operations. The detailed results of operations for these groups are presented and analyzed before the reclassification and elimination of certain intersegment transactions necessary to consolidate those results into the Company's Consolidated Condensed Statements of Income.

Results of Operations of the Utility Group

The Utility Group is comprised of Utility Holdings' operations and consists of the Company's regulated operations and other operations that provide information technology and other support services to those regulated operations. Regulated operations consist of a natural gas distribution business that provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west-central Ohio and an electric transmission and distribution business, which provides electric distribution services to southwestern Indiana, and its power generating and wholesale power operations. In total, these regulated operations supply natural gas and/or electricity to over one million customers. Utility Group operating results before certain intersegment eliminations and reclassifications for the three months ended March 31, 2013 and 2012, follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2013	2012
OPERATING REVENUES		
Gas utility	$315.9	$292.3
Electric utility	149.5	139.4
Other	0.1	0.4
Total operating revenues	465.5	432.1
OPERATING EXPENSES		
Cost of gas sold	157.2	137.1
Cost of fuel & purchased power	50.2	44.7
Other operating	86.8	79.9
Depreciation & amortization	48.4	48.6
Taxes other than income taxes	17.5	15.9
Total operating expenses	360.1	326.2
OPERATING INCOME	105.4	105.9
OTHER INCOME - NET	1.8	2.2
INTEREST EXPENSE	17.9	17.7
INCOME BEFORE INCOME TAXES	89.3	90.4
INCOME TAXES	34.2	34.4
NET INCOME	$55.1	$56.0
CONTRIBUTION TO VECTREN BASIC EPS	$0.67	$0.69

Utility Group Margin

Throughout this discussion, the terms Gas Utility margin and Electric Utility margin are used. Gas Utility margin is calculated as Gas utility revenues less the Cost of gas sold. Electric Utility margin is calculated as Electric utility revenues less Cost of fuel & purchased power. The Company believes Gas Utility and Electric Utility margins are better indicators of relative contribution than revenues since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers. Following is a discussion and analysis of margin generated from regulated utility operations.

In addition, the Company separately shows Regulatory expense recovery mechanisms within Gas utility margin and Electric utility margin. These amounts represent dollar-for-dollar recovery of operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. For example, demand side management and conservation expenses for both the gas and electric utilities; MISO administrative expenses for the Company's Electric operations; uncollectible expense associated with the Company's Ohio gas customers; and recoveries of state mandated revenue taxes in both Indiana and Ohio are included in these amounts.

Gas Utility Margin (Gas utility revenues less Cost of gas sold)
Gas Utility margin and throughput by customer type follows:

	Three Months Ended March 31,	
(In millions)	2013	2012
Gas utility revenues	$315.9	$292.3
Cost of gas sold	157.2	137.1
Total gas utility margin	$158.7	$155.2
Margin attributed to:		
Residential & commercial customers	$120.5	$117.8
Industrial customers	17.3	15.8
Other	3.0	3.4
Regulatory expense recovery mechanisms	17.9	18.2
Total gas utility margin	$158.7	$155.2
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	55.1	40.8
Industrial customers	31.0	27.8
Total sold & transported volumes	86.1	68.6

Gas Utility margins were $158.7 million for the three months ended March 31, 2013, and compared to 2012, increased $3.5 million. Excluding the impact of regulatory expense recovery mechanisms, small customer margins increased $2.7 million compared to the first quarter of 2012. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 107 percent of normal in Ohio during 2013, compared to 82 percent of normal in Ohio during 2012, had a favorable impact to small customer margin of approximately $0.7 million. Growth in residential and commercial customers favorably impacted small customer margins by approximately $1.0 million. Finally, margin related to investments in infrastructure in Ohio increased margin $1.0 million compared to the first quarter of 2012. Large customer margins increased $1.5 million on increasing volumes.

Electric Utility Margin (Electric utility revenues less Cost of fuel & purchased power)
Electric Utility margin and volumes sold by customer type follows:

	Three Months Ended March 31,	
(In millions)	2013	2012
Electric utility revenues	$149.5	$139.4
Cost of fuel & purchased power	50.2	44.7
Total electric utility margin	$99.3	$94.7
Margin attributed to:		
Residential & commercial customers	$60.7	$57.7
Industrial customers	26.1	26.6
Other customers	0.8	0.8
Regulatory expense recovery mechanisms	2.5	0.7
Subtotal: retail	$90.1	$85.8
Wholesale power & transmission system margin	9.2	8.9
Total electric utility margin	$99.3	$94.7
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	671.3	631.1
Industrial customers	659.3	681.7
Other customers	5.8	5.9

Total retail volumes sold	1,336.4	1,318.7

Retail

Electric retail utility margins were $90.1 million for the three months ended March 31, 2013, and compared to 2012, increased by $4.3 million. Excluding the impact of regulatory expense recovery mechanisms, small customer margins increased by $3.0 million. Electric results are not protected by weather mechanisms, which resulted in a $3.9 million increase in small customer margin as heating degree days in the first quarter of 2013 were 101 percent of normal compared to only 71 percent of normal in 2012. This is offset partially by $0.8 million of small customer declines resulting from conservation beyond approved lost margin recovery mechanisms. Large customer margins declined from 2012 by $0.5 million on decreasing volumes. Margin from regulatory expense recovery mechanisms increased $1.8 million from 2012, driven by increased operating expenses associated with the electric state-mandated conservation programs. This is offset by a corresponding increase in operating expenses when compared to 2012.

Margin from Wholesale Electric Activities

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of MISO's regional transmission expansion plans and also markets and sells its generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales are generated in the MISO Day Ahead and Real Time markets when sales into the MISO in a given hour are greater than amounts purchased for native load. Further detail of MISO off-system margin and transmission system margin follows:

	Three Months Ended March 31,	
(In millions)	2013	2012
Transmission system sales	$6.6	$5.9
Off-system sales	2.6	3.0
Total wholesale margin	$9.2	$8.9

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $6.6 million and $5.9 million during the three months ended March 31, 2013 and 2012, respectively. Increases are primarily due to increased investment in qualifying projects. As of December 31, 2012, the Company had invested $155 million in qualifying projects. These projects include an interstate 345 Kv transmission line that connects Vectren's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. Once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance, and operating expenses are also recovered. The 345 Kv project is the largest of these qualifying projects, with a cost of $107 million that earned the FERC approved equity rate of return while under construction. The last segment of that project was placed into service in December 2012.

For the three months ended March 31, 2013, margin from off-system sales was $2.6 million, compared to $3.0 million for the three months ended March 31, 2012. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year be shared equally with customers. Results for the periods presented reflect the impact of that sharing.

Utility Group Operating Expenses

Other Operating

For the three months ended March 31, 2013 other operating expenses were $86.8 million, an increase of $6.9 million, compared to 2012. The increased expenses result primarily from the timing of power supply operating costs associated with generation related variable production costs. For the full year 2013, the Company expects to be on track to meet its annual goal of flat operating expenses, driven largely by continued focus on performance management initiatives.

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Taxes Other Than Income Taxes
Taxes other than income taxes were $17.5 million for the quarter, an increase of $1.6 million compared to the prior year quarter. The increase is primarily due to higher usage taxes associated with higher gas and fuel costs due to increased volumes. These expenses are offset dollar-for-dollar with lower gas utility and electric utility revenues.

Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

Vectren monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. Vectren's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and operational improvement. In 2011, laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects, and in Ohio other capital investment projects, outside of a base rate proceeding. Utilization of these recovery mechanisms is discussed below.

Ohio Recovery and Deferral Mechanisms
The PUCO order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post in service carrying costs is also allowed until the related capital expenditures are recovered through the DRR. The order also established a prospective bill impact evaluation on the annual deferrals, limiting the deferrals at a level which would equal a change over the prior year rate of $1.00 per residential and general service customer per month. To date, the Company has made capital investments under this rider totaling $85 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $7.2 million and $6.5 million at March 31, 2013 and December 31, 2012, respectively. The DRR's initial five year term expires in early 2014. The Company will make a filing in May 2013 proposing to extend the term of the DRR.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. Once such application is approved, the legislation authorizes a deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law. The order provided for the deferral of depreciation, debt-related post in service carrying costs, and property taxes for its $23.5 million capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. The Company will file annually for the accounting treatment described above for its annual capital expenditure program.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received orders in 2008 and 2007 associated with the most recent base rate cases. These orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Vectren North and $3 million annually at Vectren South. The debt-related post in service carrying costs are recognized in the Consolidated Statements of Income currently. Such deferral is limited by individual qualifying project to three years after being placed into service at Vectren South and four years after being

placed into service at Vectren North.

In April 2011, Senate Bill 251 was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, along with recovery of depreciation and other operating costs associated with these

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mandates. The remaining 20 percent of those costs are to be deferred for future recovery in the utility's next general rate case. To date, the Company has not initiated a filing requesting authority to recover costs using the Senate Bill 251 approach and continues to study its applicability to expenditures associated with its natural gas distribution operations.

Pipeline Safety Law

On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years Those regulations may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the law is expected to result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses. Operating expenses associated with expanded compliance requirements may grow by approximately $9 million annually, with $6 million attributable to the Indiana operations. Related to the Indiana operations, the Company expects to seek recovery under Senate Bill 251, or such costs may be recoverable through current tracking mechanisms. Capital investments, associated with the Pipeline Safety Law, are expected to be significant. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 or other currently authorized recovery mechanisms, such as the Distribution Replacement Rider, in Ohio.

Indiana Senate Bill 560

In April 2013, Senate Bill 560 was signed into law. This legislation, which supplements Senate Bill 251 described above which addressed federally-mandated investment, provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent. The new law also provides for the use of test years in base rate cases that can include twelve month future periods beginning up to 24 months beyond the petition date. To the extent new rates are not approved within 300 days of filing the case-in-chief, or in limited cases within 360 days, 50 percent of the proposed rate increase may be implemented, subject to refund. The Company is currently evaluating the impact that these legislative actions, both Senate Bill 251 and 560, may have on its operations in future periods.

Vectren North Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The

Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. The Company seeks further clarity on the scope of the requirement and the ability to also use contractors to perform certain inspections. Testimony was filed by the Company in April 2013, with subsequent filings by the other parties scheduled for May 2013. A hearing has been scheduled for July 2013 and an order is expected in 2013.

Environmental Matters

Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting Vectren South's electric operations. The Company is currently evaluating the impact Senate Bill 251 may have on its operations, including applicability to the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality

Clean Air Interstate Rule / Cross-State Air Pollution Rule

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO_2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO_2 and NOx allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSAPR set individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances to generating units through state implementation plans, CSAPR allowances were allocated to individual units directly through the federal rule. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. Multiple administrative and judicial challenges were filed. On December 30, 2011, the Court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the Court vacated CSAPR and directed the EPA to continue to administer CAIR. In October 2012, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. EPA's request for rehearing was denied by the Court on January 24, 2013. In March 2013, the EPA filed a petition for review with the US Supreme Court. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air Regulations").

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule is the EPA's response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR's implementation by the Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA agreed to reconsider MATS requirements for new construction. Such requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013.

Conclusions Regarding Air Regulations

To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining

SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO_2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the 2015 requirement imposed by CAIR, and the NOV discussed above. Due to the correlation amongst the various requirements set forth, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required and could be significant depending on the required method of compliance with the requirements. While the Company has not yet quantified what the additional costs may be associated with these efforts, because the compliance is required by government regulation the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above.

Information Request

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the information request.

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized, the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2013. Depending on the final rule and on the Company's facts and circumstances, capital investments could approximate $40 million if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 and the Company is reviewing the proposal. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recovered under Senate Bill 251 referenced above.

Coal Ash Waste Disposal & Ash Ponds

In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules have not been finalized given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company’s ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as$30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recovered under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two greenhouse gas regulations that apply to the Company’s generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. EPA's PSD and Title V permitting rules for GHG's were recently upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards for greenhouse gases for new electric generating facilities under Clean Air Act Section 111(b). EPA missed its deadline for finalization of the new source rule in April, and has indicated that it will finalize the new source rule within the next 18 months. Upon finalization of the new source rule, the EPA intends to propose New Source Performance Standards for greenhouse gases for existing electric generating units under Section 111(d), which would be applicable to the Company's existing units. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown

If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other greenhouse gases or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company’s fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. The financial incentives include an enhanced return on equity and tracking mechanisms to recover program costs. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2009, the Company also executed a long term purchase power commitment for 50 MW of wind energy. These transactions supplement a 30 MW wind energy purchase power agreement executed in 2008. Before the impacts of efficiency measures which are defined as clean energy in the legislation, the Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. The Company continues to evaluate whether to participate in this voluntary program.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/feasibility study (RI/FS) was completed at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO’s service territory, all of which are currently enrolled in the IDEM’s VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $42.4 million ($23.2 million at Indiana Gas and $19.2 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.2 million of the expected $15.5 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of March 31, 2013 and December 31, 2012, approximately $5.2 million and $4.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

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Results of Operations of the Nonutility Group

The Nonutility Group operates in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. There are also other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. The Nonutility Group supports the Company’s regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services. Nonutility Group earnings for the three months ended March 31, 2013 and 2012 follow:

	Three Months Ended March 31,	
(In millions, except per share amounts)	2013	2012
NET (LOSS)	$(5.4)	$(4.8)
CONTRIBUTION TO VECTREN BASIC EPS	$(0.06)	$(0.06)
NET INCOME (LOSS) ATTRIBUTED TO:		
Infrastructure Services	$6.9	$3.0
Energy Services	(1.4)	(1.7)
Coal Mining	(6.0)	(0.3)
Energy Marketing - ProLiance	(4.6)	(5.9)
Other Businesses	(0.3)	0.1

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly-owned subsidiaries Miller Pipeline, LLC (Miller) and Minnesota Limited, LLC (Minnesota Limited). Inclusive of holding company costs, earnings from Infrastructure Services' operations for the three months ended March 31, 2013 were $6.9 million, compared to $3.0 million in the prior year quarter. The increase in earnings reflects increased demand for services, which was partially offset by the impacts of unfavorable weather on certain distribution projects. Revenues during the first quarter of 2013 were $172 million, compared to revenues in the first quarter of 2012 of $118 million. Construction activity generally is expected to remain strong as companies replace their aging natural gas infrastructure. In addition, construction activity is expected to be favorably impacted as pipeline operators construct new pipelines due to the continued strong demand for shale gas and oil infrastructure. As an example, in the fourth quarter of 2012, Infrastructure Services was awarded a contract to construct an approximate 80 mile natural gas pipeline in the Bakken Shale area of North Dakota. It is expected this work will be completed by the end of the second quarter of 2013.

Energy Services

Energy Services provides energy performance contracting and renewable energy services through wholly-owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' operation contributed a loss of $1.4 million during the first quarter of 2013, compared to a loss of $1.7 million in 2012.

The smaller loss in the first quarter of 2013 reflects increased tax deductions associated with energy efficiency projects in accordance with IRS guidance released in 2012. This favorable impact to results in the first quarter of 2013 was partially offset by a slight reduction in revenues which continues to indicate near-term slowing in demand for performance contracting projects due to budgetary constraints on municipal and school customers. As of March 31, 2013, performance contracting backlog was $71 million, compared to $77 million on December 31, 2012. ESG continues to strategically add to its employee base and footprint to position it for growth in this sector as the national focus on energy conservation, renewable energy, and sustainability continues for the long term given the expected rise in power prices across the country.

Coal Mining

Coal Mining owns mines that produce and sell coal to the Company’s utility operations and to third parties through its wholly-owned subsidiary Vectren Fuels, Inc. (Vectren Fuels). Results from Coal Mining, inclusive of holding company costs, were a loss of $6.0 million in the first quarter of 2013, compared to a loss of $0.3 million in the prior year.

While coal sales and related revenues were up slightly from the prior year, results in 2013 were lower due to increased production costs associated with a thin coal seam and other unfavorable mining conditions at Prosperity mine. Results during the first quarter also reflect reduced pricing for customers associated with contracts that had price reopener clauses during 2012 and the overall softness in the coal market. The impact of the low cost of natural gas and mild weather in the prior year resulted in customers' coal-fired generating plants not operating at capacity and a resulting increase in their coal inventory, which led to decreased coal purchases from Vectren Fuels thus far in 2013.

Vectren Fuels' expected production is now approximately 6.2 million tons in 2013. Coal sales in 2013 are estimated at 6.3 million tons. The Company's second mine at its Oaktown mining complex began production in April 2013. Vectren Fuels continues to implement changes in its mining plan to reduce its on-going mining costs at Prosperity, including moving its continuous mining equipment in April to areas of the mine with thicker coal seams and the utilization of low profile equipment. However, given the reduced demand for coal generally, and its impact on price, the Company continues to expect a greater loss from Coal Mining operations in 2013 compared to 2012. Longer term, the Company continues to believe that reduced coal volumes available from Central Appalachia due to increased regulation and the large number of scrubbers to be installed throughout the United States, including the Midwest, coupled with moderate increases in natural gas prices from the very low levels experienced in 2012, should drive stronger demand for Illinois Basin coal. Changes in market conditions or other circumstances could cause actual results to be materially different from these expectations.

Coal Reserves

As of March 31, 2013, management estimates the Company’s total Illinois Basin coal reserves to be approximately 126 million tons. Once the Company's second mine at its Oaktown mining complex is in full production, Vectren Fuels underground mines are capable of producing about 7.5 million tons of coal per year.

Mine Safety Information

The Company retains independent third party contract mining companies to operate its coal mines. Five Star Mining LLC ("Five Star") is the contract mining company at the Prosperity underground mine and Black Panther Mining LLC ("Black Panther") is the contract mining company at the Oaktown underground mines. The contract mining companies are the mine “operator”, as that term is used in both the Federal Mine Safety and Health Act of 1977 (the “Mine Act”) and the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010. All employees at the coal mines are hired, supervised, and paid by the contract mining companies. As the mine operator, the contract mining companies make all regulatory filings required by the MSHA. In most circumstances, however, the cost of fines and penalties assessed by MSHA are contractually passed through from the contract mining company to Vectren Fuels. The process of settling such claims can take years in certain circumstances. During the three months ended March 31, 2013, the Company paid approximately $0.2 million related to assessments issued to the mine operators.

More detailed information about the Company’s mines, including safety-related data, can be found at MSHA’s website, www.MSHA.gov. Prosperity operates under the MSHA identification number 1202249; Oaktown 1 operates under the identification number 1202394; and Oaktown 2 operates under the identification number 1202418. Mine safety-related data included on the MSHA website is influenced by the size of the mine, the level of activity at the mine, and the mine inspector’s judgment, among other factors. These factors can impact the comparability of information from mine to mine and time period to time period.

Given incidents at coal mines of other companies, a significant increase in the frequency and scope of MSHA inspections continues. The MSHA recently proposed new regulations related to the level of allowable respirable dust and the utilization of proximity detection devices. In addition, MSHA no longer has to wait for final orders of citations before placing a mine on a “pattern of violation” status, and the initial step of notifying mine operators and giving them time to reduce instances of violations has been eliminated.

Energy Marketing

ProLiance

ProLiance, a nonutility energy marketing affiliate of Vectren and Citizens, provides services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance's customers include Vectren's Indiana utilities and Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. Consistent with its ownership percentage, Vectren is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member. The Company accounts for its investment in ProLiance using the equity method of accounting. On March 17, 2011, an order was received from the IURC providing for ProLiance's continued provision of gas supply services to the Company's Indiana utilities and Citizens through March 2016.

Vectren Energy Marketing and Services, Inc (EMS), a wholly owned subsidiary, holds the Company's investment in ProLiance. EMS is responsible for certain financing costs associated with ProLiance and is also responsible for income taxes and allocated corporate expenses related to the Company's portion of ProLiance's results. During the three months ended March 31, 2013 and 2012, EMS' results related to the Company's share of ProLiance's losses, which include financing costs, income taxes, and other holding company costs, were a loss of $4.6 million, compared to a loss of $5.9 million in 2012. The smaller loss in the first quarter of 2013 primarily reflects the reduction in fixed demand costs for both storage and transportation contracts.

Efforts to lower the cost of pipeline and storage demand costs continue. Through negotiations and by dropping some uneconomical contracts as they expire, ProLiance has lowered its pipeline transportation and storage demand costs to approximately $42 million for all of 2013, compared to $55 million in 2012. In addition to this reduction, opportunities exist through expirations to renegotiate or drop contracts with annual demand costs of approximately $9 million by the end of 2015. Changes in market conditions or other circumstances could cause actual demand costs to be materially different from this expectation. At March 31, 2013, ProLiance had approximately $115 million of members' equity on its balance sheet, no long-term debt outstanding, and borrowings of $31 million on its $120 million credit facility, which expires in May 2014.

For the three months ended March 31, 2013 and 2012, the amounts recorded to Equity in (losses) of unconsolidated affiliates related to ProLiance's operations totaled a pre-tax loss of $6.0 million and $7.6 million, respectively.

The Company continues its emphasis in the Nonutility Group on growing its infrastructure and energy services businesses rather than its commodities businesses. As such, analysis and evaluation of strategic alternatives related to the investment in its energy marketing affiliate, ProLiance Holdings is ongoing. The Company believes the carrying value of its investment in ProLiance Holdings at March 31, 2013 is appropriate, but if the Company proceeds with one of the strategic alternatives being evaluated, which could include a disposition of its investment in ProLiance Holdings or a disposition by ProLiance Holdings of one or more of its operating subsidiaries or their assets, the amount realized could be materially below the carrying value of the Company's investment of $68.1 million. In such event, the Company would record such loss as Equity in (losses) of unconsolidated affiliates.

Investment in Liberty Gas Storage

Liberty Gas Storage, LLC (Liberty), a joint venture between a subsidiary of ProLiance and a subsidiary of Sempra Energy (SE), is a development project for salt-cavern natural gas storage facilities. ProLiance is the minority member with a 25 percent interest, which it accounts for using the equity method. The project was expected to include 17 Bcf of capacity in its North site, and an additional capacity of at least 17 Bcf at the South site. The South site also has the potential for further expansion. The Liberty pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and will connect area LNG regasification terminals to an interstate natural gas transmission system and storage facilities.

In late 2008, the project at the North site was halted due to subsurface and well-completion problems, which resulted in Liberty recording a $132 million impairment charge. The Company, through ProLiance, recorded its share of the charge in 2009. As a result of the issues encountered at the North site, Liberty requested and the FERC approved the separation of the North site from the South site. Approximately 12 Bcf of the storage at the South site, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to connect the caverns to the pipeline system. ProLiance's investment in Liberty is approximately $35.6 million.

Liberty received a demand for Arbitration from Williams Midstream Natural Gas Liquids, Inc. (“Williams”) on February 8, 2011 related to a Sublease Agreement (“Sublease”) between Liberty and Williams at the North site. Williams alleges that Liberty was negligent in its attempt to convert certain salt caverns to natural gas storage and thereby damaged the caverns. Williams alleges damages of $56.7 million. Liberty believes that it has complied with all of its obligations to Williams, including properly terminating the Sublease. Liberty intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of March 31, 2013, ProLiance has no material reserve recorded related to this matter and this litigation has not materially impacted ProLiance's results of operations or statement of financial position.

Impact of Recently Issued Accounting Guidance

Offsetting Assets and Liabilities

In January 2013, the FASB issued new accounting guidance on disclosures of offsetting assets and liabilities. This guidance amends prior requirements to add clarification to the scope of the offsetting disclosures. The amendment clarifies that the scope applies to derivative instruments accounted for in accordance with reporting topics on derivatives and hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with US GAAP or subject to an enforceable master netting arrangement or similar agreement. This guidance is effective for fiscal years beginning on or after January 1, 2013 and interim periods within annual periods. The Company adopted this guidance as of January 1, 2013. The adoption of this guidance did not have a material impact on the Company's financial statements.

Accumulated Other Comprehensive Income (AOCI)

In February 2013, the FASB issued new accounting guidance on the reporting of reclassifications from AOCI. The guidance requires an entity to report the effect of significant reclassification from AOCI on the respective line items in net income if the amount being reclassified is required under US GAAP to be reclassified in its entirety to net income. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference to other disclosures required that provide additional details about these amounts. The new guidance is effective for fiscal years, and interim periods within annual periods, beginning after December 15, 2012. The Company adopted this guidance as of January 1, 2013. The adoption of this guidance did not have a material impact on the Company's financial statements.

Financial Condition

Within Vectren's consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corp (Vectren Capital) funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital's debt, but does not guarantee Utility Holdings' debt. Vectren Capital's long-term debt, including current maturities, and short-term obligations outstanding at March 31, 2013 approximated $450 million and $167 million, respectively. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt, including current maturities, and short-term obligations outstanding at March 31, 2013 approximated $821 million and $27 million, respectively. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at March 31, 2013, approximated $387 million.

The Company's common stock dividends are primarily funded by utility operations. Nonutility operations have demonstrated profitability and the ability to generate cash flows. These cash flows are primarily reinvested in other nonutility ventures, but are also used to fund a portion of the Company's dividends, and from time to time may be reinvested in utility operations or used for corporate expenses.

The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at March 31, 2013, are A-/A3 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. The credit ratings on SIGECO's secured debt are A/A1. Utility Holdings' commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 48 percent of long-term capitalization at both March 31, 2013 and December 31, 2012. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders' equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of March 31, 2013, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

The Company's A-/A3 investment grade credit ratings have allowed it to access the capital markets as needed, and the Company believes it will have the ability to continue to do so. Given the Company's intent to maintain a balanced long-term capitalization ratio, it anticipates funding future capital expenditures and dividends principally through internally generated funds, which have recently been enhanced by bonus depreciation legislation, and refinancing maturing or callable debt using the capital markets. However, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline infrastructure replacement; coal mine safety; expanded EPA regulations for air, water, and fly ash; and growth of infrastructure Services and Energy Services. These regulations may result in the need to raise additional capital in the coming years. In addition, the Company may expand its businesses through acquisitions and/or joint venture investment. The timing and amount of such investments depends on a variety of factors, including the availability of acquisition targets and available liquidity. The Company may also consider disposing of certain assets, investments, or businesses to enhance or accelerate internally generated cash flow.

Specifically for 2013, the Company plans to access the capital markets to refinance debt maturities or debt that is callable. On April 1, 2013, the Company executed an early redemption at par of $121.6 million 6.25 percent senior unsecured notes of VUHI due in 2039. This debt will be refinanced with proceeds from a private placement note purchase agreement with a delayed draw feature entered into on December 20, 2012 by Utility Holdings and institutional investors. It provides for the following tranches of notes: (i) $45 million 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million 4.25 percent senior guaranteed notes, due June 5, 2043. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. Subject to the satisfaction of customary conditions precedent, this financing is scheduled to close on or about June 5, 2013. As of March 31, 2013, the $121.6 million was classified as Current maturities of long-term debt.

In April 2013, approximately $89 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. In May 2013, an additional $22 million of SIGECO's tax-exempt long-term debt will be redeemed at par plus accrued interest pursuant to notice provided to the holders thereof. In April 2013, $111 million of new SIGECO tax-exempt debt was issued to refund this debt. Approximately $62 million of this debt was issued at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043. The remaining $49 million of the called debt will be held by Utility Holdings and will be remarketed at a future date. As of March 31, 2013, the $111 million of SIGECO tax-exempt debt remained classified as long-term.

Consolidated Short-Term Borrowing Arrangements

At March 31, 2013, the Company has $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly-owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $323 million was available for the Utility Group operations and approximately $83 million was available for the wholly-owned Nonutility Group and corporate operations. Both Vectren Capital's and Utility Holdings' short-term credit facilities are available through September 2016. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis.

The Company has historically funded the short-term borrowing needs of Utility Holdings' operations through the commercial paper market and expects to use the Utility Holdings short-term borrowing facility in instances where the commercial paper market is not efficient. Following is certain information regarding these short-term borrowing arrangements.

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2013	2012	2013	2012
Quarter End				
Balance Outstanding	$27.1	$49.7	$166.5	$125.0
Weighted Average Interest Rate	0.36%	0.43%	1.35%	1.42%
Quarterly Average				
Balance Outstanding	$63.1	$113.4	$142.9	$76.1
Weighted Average Interest Rate	0.38%	0.49%	1.38%	1.42%
Maximum Month End Balance Outstanding	$75.1	$214.2	$166.5	$125.0

ProLiance Short-Term Borrowing Arrangements

ProLiance has separate borrowing capacity available through a syndicated credit facility. On May 18, 2012, ProLiance entered into a two year asset based credit facility with a total capacity of $120 million. The level of capacity is also subject to outstanding letters of credit and current inventory and receivable balances. As of March 31, 2013, approximately $31 million in borrowings were outstanding. The facility is not guaranteed by Vectren or Citizens.

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan, stock option plan and other employee benefit plan requirements. New issuances added additional liquidity of $2.3 million and $1.6 million in the three months ended March 31, 2013 and 2012, respectively.

Potential Uses of Liquidity

Pension Funding Obligations

Management currently estimates contributing approximately $10 million to qualified pension plans in 2013, with contributions totaling $2.5 million in the three months ended March 31, 2013.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At March 31, 2013, parent level guarantees support a maximum of $25 million of ESG's performance contracting commitments and warranty obligations and $45 million of other project guarantees. The broader scope of ESG's performance contracting obligations, including those not guaranteed by the parent company, are described below. In addition, the parent company has approximately $22 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $16 million represent letters of credit supporting other nonutility operations. Guarantees issued and outstanding on behalf of unconsolidated affiliates approximated $3 million at March 31, 2013. These guarantees relate primarily to arrangements between ProLiance and various natural gas pipeline operators. The Company has not been called upon to satisfy any obligations pursuant to these parental guarantees and has accrued no significant liabilities related to these guarantees.

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized for the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at March 31, 2013, there are 53 open surety bonds supporting future performance. The average face amount of these obligations is $5.8 million, and the largest obligation has a face amount of $57.3 million. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At March 31, 2013, approximately 54 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years. The Company has no significant accruals for these warranty obligations as of March 31, 2013. In addition, ESG has an $8 million stand-alone letter of credit facility and as of March 31, 2013, $3.4 million was outstanding.

Other Letters of Credit

As of March 31, 2013, Utility Holdings has letters of credit outstanding in support of two SIGECO tax exempt adjustable rate first mortgage bonds totaling $41.7 million. In the unlikely event the letters of credit were called, the Company could settle with the financial institutions supporting these letters of credit with general assets or by drawing from its credit facility that expires in September 2016. Due to the long-term nature of the credit agreement, such debt is classified as long-term at March 31, 2013.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at $243 million for the remainder of 2013. Nonutility capital expenditures and investments are estimated at $79 million for the remainder of 2013.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $185.5 million and $168.8 million for the three months ended March 31, 2013 and 2012, respectively. The increased cash flow from operations reflects increased volumetric recoveries of Regulatory assets during the first quarter of 2013 associated with weather that was colder than the prior year. In addition, payments related to environmental remediation matters and contributions to benefit plans were higher during the first quarter of 2012 compared to 2013.

Financing Cash Flow

Net cash flow required for financing activities was $112.5 million during the three months ended March 31, 2013 compared to requirements of $81.5 million in 2012. Financing activity in both periods presented reflects the payment of dividends and the repayment of short-term borrowings. Financing activity in 2012 also included $100 million in debt issuance by Utility Holdings.

Investing Cash Flow

Cash flow required for investing activities was $80.4 million and $81.7 million during the three months ended March 31, 2013 and 2012, respectively. The primary use of cash in both periods presented reflect expenditures for utility and nonutility capital investments.

Forward-Looking Information

A "safe harbor" for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in Management's Discussion and Analysis of Results of Operations and Financial Condition are forward-looking statements. Such statements are based on management's beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words "believe", "anticipate", "endeavor", "estimate", "expect", "objective", "projection", "forecast", "goal", "likely", and expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to fossil fuel costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.

- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks, or other similar occurrences could adversely affect Vectren's facilities, operations, financial condition and results of operations.
- Increased competition in the energy industry, including the effects of industry restructuring and unbundling.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under traditional regulation, and the frequency and timing of rate increases.

- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, coal, and other nonutility products and services; impacts on both gas and electric large customers; lower residential and commercial customer counts; higher operating expenses; and further reductions in the value of certain nonutility real estate and other legacy investments.
- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, interest rate, and warranty risks.
- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- The performance of projects undertaken by the Company's nonutility businesses and the success of efforts to invest in and develop new opportunities, including but not limited to, the Company's infrastructure services, energy services, coal mining, and energy marketing strategies.
- Factors affecting infrastructure services, including the level of success in bidding contracts; fluctuations in volume of contracted work; unanticipated cost increases in completion of the contracted work; funding requirements associated with multi-employer pension plans; changes in legislation and regulations impacting the industries in which the customers served operate; the effects of weather; failure to properly estimate the cost to construct projects; the ability to attract and retain qualified employees; cancellation and/or reductions in the scope of projects by customers; credit worthiness of customers; ability to obtain materials and equipment required to perform services; and changing market conditions.
- Factors affecting coal mining operations and their cost structure, including MSHA guidelines and interpretations of those guidelines, as well as additional mine regulations and more frequent and broader inspections that could result from mining incidents at coal mines of other companies; geologic, equipment, and operational risks; the ability to execute and negotiate new sales contracts and resolve contract interpretations; volatile coal market prices and demand; supplier and contract miner performance; the availability of key equipment, contract miners and commodities; availability of transportation; coal quality, including its sulfur and mercury content; and the ability to access coal reserves.
- Factors affecting the Company's investment in ProLiance including natural gas price volatility and basis; the ability to lower fixed contract costs; and availability of credit.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as mergers, acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with state and federal laws and interpretations of these laws.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of changes in actual results, changes in assumptions, or other factors affecting such statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company's risk management program includes, among other things, the use of derivatives. The Company executes derivative contracts in the normal course of operations while buying and selling commodities and occasionally when managing interest rate risk.

The Company has in place a risk management committee that consists of senior management as well as financial and operational management. The committee is actively involved in identifying risks as well as reviewing and authorizing risk mitigation strategies.

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Vectren 2012 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended March 31, 2013, there have been no changes to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of March 31, 2013, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of March 31, 2013, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:
1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II

ITEM 1. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate and regulatory matters. The consolidated condensed financial statements are included in Part 1 Item 1.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company's operating results and financial condition, causing them to be materially adversely affected. The Company's risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2012 Form 10-K and are therefore not presented herein.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company's share-based compensation plans; however, no such open market purchases were made during the quarter ended March 31, 2013.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

31.1 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer

31.2 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer

32 Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002

101 Interactive Data File.

101.INS XBRL Instance Document

101.SCH XBRL Taxonomy Extension Schema

101.CAL XBRL Taxonomy Extension Calculation Linkbase

101.DEF XBRL Taxonomy Extension Definition Linkbase

101.LAB XBRL Taxonomy Extension Labels Linkbase

101.PRE XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

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

VECTREN CORPORATION
Registrant

May 2, 2013

/s/Jerome A. Benkert, Jr.
Jerome A. Benkert, Jr.
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/M. Susan Hardwick
M. Susan Hardwick
Vice President, Controller and Assistant Treasurer
(Principal Accounting Officer)