VECTREN CORP
Form 10-Q
May 12, 2014

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, 2014

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	82,464,845	April 30, 2014
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
		vvcir@vectren.com

Definitions

BCF: billions of cubic feet

BTU: British thermal units

DOT: Department of Transportation

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

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	March 31, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash & cash equivalents	$54.5	$21.5
Accounts receivable - less reserves of $8.2 & $6.8, respectively	272.4	259.2
Accrued unbilled revenues	123.4	134.2
Inventories	105.3	134.4
Recoverable fuel & natural gas costs	27.1	5.5
Prepayments & other current assets	30.0	75.6
Total current assets	612.7	630.4
Utility Plant		
Original cost	5,438.9	5,389.6
Less: accumulated depreciation & amortization	2,198.8	2,165.3
Net utility plant	3,240.1	3,224.3
Investments in unconsolidated affiliates	23.9	24.0
Other utility & corporate investments	38.2	38.1
Other nonutility investments	34.0	33.8
Nonutility plant - net	655.5	657.2
Goodwill - net	262.3	262.3
Regulatory assets	171.6	193.4
Other assets	37.5	39.1
TOTAL ASSETS	$5,075.8	$5,102.6

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

3

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

	March 31, 2014	December 31, 2013
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$206.9	$227.2
Refundable fuel & natural gas costs	—	2.6
Accrued liabilities	201.4	182.1
Short-term borrowings	54.2	68.6
Current maturities of long-term debt	5.0	30.0
Total current liabilities	467.5	510.5
Long-term Debt - Net of Current Maturities	1,772.2	1,777.1
Deferred Credits & Other Liabilities		
Deferred income taxes	698.8	707.4
Regulatory liabilities	393.4	387.3
Deferred credits & other liabilities	166.3	166.0
Total deferred credits & other liabilities	1,258.5	1,260.7
Commitments & Contingencies (Notes 7, 9-11)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 82.5 & 82.4 shares, respectively	711.1	709.3
Retained earnings	867.2	845.7
Accumulated other comprehensive (loss)	(0.7)	(0.7)
Total common shareholders' equity	1,577.6	1,554.3
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$5,075.8	$5,102.6

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

4

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

	Three Months Ended March 31,	
	2014	2013
OPERATING REVENUES		
Gas utility	$443.6	$315.9
Electric utility	163.0	149.5
Nonutility	190.2	235.2
Total operating revenues	796.8	700.6
OPERATING EXPENSES		
Cost of gas sold	270.9	157.2
Cost of fuel & purchased power	57.0	50.2
Cost of nonutility revenues	67.7	86.4
Other operating	207.6	215.6
Depreciation & amortization	73.8	66.2
Taxes other than income taxes	20.8	18.2
Total operating expenses	697.8	593.8
OPERATING INCOME	99.0	106.8
OTHER INCOME (EXPENSE)		
Equity in (losses) of unconsolidated affiliates	(0.1)	(6.7)
Other income – net	4.3	2.9
Total other income (expense)	4.2	(3.8)
INTEREST EXPENSE	22.1	23.5
INCOME BEFORE INCOME TAXES	81.1	79.5
INCOME TAXES	29.9	29.7
NET INCOME	$51.2	$49.8
AVERAGE COMMON SHARES OUTSTANDING	82.4	82.2
DILUTED COMMON SHARES OUTSTANDING	82.5	82.3
EARNINGS PER SHARE OF COMMON STOCK:		
BASIC	$0.62	$0.61
DILUTED	$0.62	$0.61
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.360	$0.355

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

5

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

	Three Months Ended March 31,	
	2014	2013
Net income	$51.2	$49.8
Other comprehensive income (OCI) of unconsolidated affiliates		
Net amount arising during the year before tax	—	0.2
Income taxes related to items of other comprehensive income	—	(0.1)
AOCI of unconsolidated affiliates, net of tax	—	0.1
Total comprehensive income	$51.2	$49.9

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

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

	Three Months Ended March 31,	
	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$51.2	$49.8
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	73.8	66.2
Deferred income taxes & investment tax credits	5.7	14.2
Equity in losses of unconsolidated affiliates	0.1	6.7
Provision for uncollectible accounts	2.3	2.4
Expense portion of pension & postretirement benefit cost	1.0	2.2
Other non-cash charges - net	2.9	3.5
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	(4.9)	(30.5)
Inventories	29.1	35.1
Recoverable/refundable fuel & natural gas costs	(24.2)	15.1
Prepayments & other current assets	38.4	31.3
Accounts payable, including to affiliated companies	(20.0)	(16.2)
Accrued liabilities	19.2	3.0
Employer contributions to pension & postretirement plans	(0.9)	(3.4)
Changes in noncurrent assets & investments	9.1	5.0
Changes in noncurrent liabilities	(0.8)	1.1
Net cash provided by operating activities	182.0	185.5
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Dividend reinvestment plan & other common stock issuances	1.7	2.3
Requirements for:		
Dividends on common stock	(29.7)	(29.2)
Retirement of long-term debt	(30.0)	(0.4)
Net change in short-term borrowings	(14.4)	(85.2)
Net cash used in financing activities	(72.4)	(112.5)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from:		
Other collections	1.1	0.3
Requirements for:		
Capital expenditures, excluding AFUDC equity	(77.7)	(80.4)
Other investments	—	(0.3)
Net cash used in investing activities	(76.6)	(80.4)
Net change in cash & cash equivalents	33.0	(7.4)
Cash & cash equivalents at beginning of period	21.5	19.5
Cash & cash equivalents at end of period	$54.5	$12.1

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

7

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO THE CONDENSED CONSOLIDATED 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 581,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 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 316,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is currently involved in nonutility activities in three primary business areas: Infrastructure Services, Energy Services, and Coal Mining. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Coal Mining owns, and through its contract miners, mines and then sells coal. Enterprises supports the Company’s regulated utilities by providing infrastructure services and coal. 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. Prior to June 18, 2013, the Company, through Enterprises, had activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance).

2. Basis of Presentation

The interim condensed consolidated 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 condensed consolidated 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, 2013, filed with the Securities and Exchange Commission on February 20, 2014, 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.

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. 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)	2014	2013
Numerator:		
Reported net income (Numerator for Basic and Diluted EPS)	$51.2	$49.8
Denominator:		
Weighted average common shares outstanding (Denominator for Basic EPS)	82.4	82.2
Conversion of share based compensation arrangements	0.1	0.1
Adjusted weighted average shares outstanding and assumed conversions outstanding (Denominator for Diluted EPS)	82.5	82.3
Basic EPS	$0.62	$0.61
Diluted EPS	$0.62	$0.61

For the three months ended March 31, 2014 and 2013, all options and equity based instruments 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 $12.9 million and $10.7 million in the three months ended March 31, 2014 and 2013, 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."

9

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)	2014	2013	2014	2013
Service cost	$1.8	$2.1	$0.1	$0.1
Interest cost	3.9	3.7	0.5	0.5
Expected return on plan assets	(5.7)	(5.5)	—	—
Amortization of prior service cost	0.3	0.4	(0.7)	(0.8)
Amortization of transitional obligation	—	—	—	—
Amortization of actuarial loss	1.2	2.5	0.1	0.2
Net periodic benefit cost	$1.5	$3.2	$—	$—

Employer Contributions to Qualified Pension Plans

Currently, the Company anticipates making no contributions to its qualified pension plans in 2014.

6. Supplemental Cash Flow Information

As of March 31, 2014 and December 31, 2013, the Company has accruals related to utility and nonutility plant purchases totaling approximately $15.1 million and $19.4 million, respectively.

7. Investment in ProLiance Holdings, LLC

The Company has an investment in ProLiance, a nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets, along with the long-term pipeline and storage commitments, of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy), to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). Vectren's remaining investment in ProLiance relates primarily to ProLiance's investment in LA Storage, LLC (LA Storage). 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.

As a result of ProLiance exiting the natural gas marketing business on June 18, 2013, the Company recorded its share of the loss on the disposition, termination of long term pipeline and storage commitments, and related transaction and other costs totaling $43.6 million pre-tax, or $26.8 million net of tax, during the second quarter of 2013. At the time of the sale, ProLiance funded an estimated equity shortfall at ProLiance Energy of $16.6 million. To fund this estimated shortfall, the Company issued a note to ProLiance for its 61 percent ownership share of the $16.6 million shortfall, or $10.1 million, which was utilized by ProLiance to invest additional equity in ProLiance Energy. This interest-bearing note is classified as Other nonutility investments in the Condensed Consolidated Balance Sheets.

In addition, in connection with the disposition, the Company and Citizens issued a guarantee to ETC. The guarantee issued by the Company and Citizens is a backup guarantee to the $50 million guarantee issued by ProLiance to ETC, and provides for a maximum guarantee of $25.0 million, or $15.3 million for the Company's 61 percent ownership share, and extends until June 2016. This guarantee will be called upon only in the event of default as defined in the asset sale agreement and only if the ProLiance guarantee is not sufficient to satisfy the relevant obligations. Although there can be no assurance that these guarantees will not be called upon, the Company believes that the likelihood that the Company or ProLiance will be called upon to satisfy any obligations pursuant to these guarantees is remote.

Pursuant to FERC approval, ETC ProLiance Energy has taken assignment of the Portfolio Administration Agreements (PAAs) pursuant to which the utilities receive gas supply. ETC ProLiance Energy will fulfill the requirements of the PAAs through their remaining term ending in March 2016.

On March 19, 2014, Constellation Energy Group, LLC, a subsidiary of Exelon Corporation, announced it had reached an agreement to purchase ETC ProLiance Energy. That transaction did not change ETC ProLiance Energy's obligations to fulfill the terms of the PAAs, nor did it terminate the Company's guarantee to ETC as described above.

Vectren's remaining investment in ProLiance at March 31, 2014 is as follows and reflects that it relates primarily to ProLiance's investment in LA Storage, LLC (LA Storage) discussed below.

(In millions)	As of March 31, 2014
ProLiance Energy	$1.2
Midstream assets and cash from sale of storage assets	7.8
Liberty	21.7
Total investment in ProLiance	$30.7
Included in:	
Investments in unconsolidated affiliates	$20.6
Other nonutility investments	$10.1

LA Storage, LLC Storage Asset Investment

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S 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 liquefied natural gas 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 the joint venture 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, the joint venture 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, 2014 and December 31, 2013, ProLiance's investment in the joint venture was $35.6 million and $35.4 million, respectively.

The joint venture received a demand for arbitration from Williams Midstream Natural Gas Liquids, Inc. ("Williams") in February 2011 related to a sublease agreement. Williams alleges that the joint venture was negligent in its attempt to convert certain salt caverns to natural gas storage and seeks damages of $56.7 million. The joint venture intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of March 31, 2014, 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

The Company had no purchases from ProLiance for resale and for injections into storage for the three months ended March 31, 2014 as a result of ProLiance exiting the natural gas marketing business. For the three months ended March 31, 2013, purchases totaled $107.6 million. The Company did not have any amounts owed to ProLiance for purchases at March 31, 2014 or at December 31, 2013.

11

8. Financing Activities

Vectren Capital Unsecured Note Retirement
On March 11, 2014, a $30 million Vectren Capital senior unsecured note matured. The Series A note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.37 percent. The repayment of debt was funded from the Company's short-term credit facility.

9. Commitments & Contingencies

Commitments
The Company's regulated utilities have both firm and non-firm commitments to purchase natural gas, electricity, and coal as well as certain transportation and storage rights and certain contracts are firm commitments under five and ten year arrangements. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

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, 2014, parent level guarantees support a maximum of $25 million of Energy System Group’s (ESG) performance contracting commitments and warranty obligations and $45 million of other project guarantees.

On April 1, 2014, Energy Systems Group acquired the federal sector energy services unit of Chevron Energy Solutions (CES), from Chevron USA. Pursuant to the agreement, the acquisition includes a provision whereby Vectren Enterprises, Inc., another wholly owned subsidiary of the Company and the holding company for the Company's nonutility investments, provides CES with an indemnification for potential claims against the seller that could arise related to the performance of work undertaken by ESG. The acquisition includes ESG guarantees of performance under certain assumed contracts. The guarantees include energy savings that are used to satisfy project financing. The total maximum amount of the energy savings guarantees is approximately $150 million and will only be called upon in the event energy savings established under the existing contracts executed by CES are not achieved. The Company guarantees ESG’s performance under these energy savings guarantees. Further, an energy facility operated by ESG and managed by Keenan Ft Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Vectren Enterprises, Inc. provision providing indemnification to CES and the Company guarantee of the Keenan Ft Detrick Energy operations agreement with Keenan as discussed above, do not state a maximum guarantee. Due to the nature of work performed under these contracts, the Company cannot estimate a maximum potential amount of future payments.

As disclosed in Note 7, a guarantee issued and outstanding to an unrelated party in connection with ProLiance's disposition of certain of the net assets of ProLiance Energy totaled $15.3 million at March 31, 2014. In addition, the Company has approximately $25 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $19 million represent letters of credit supporting other nonutility operations.

While there can be no assurance that neither the Vectren Enterprises, Inc.'s indemnification nor the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

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, 2014, there are 50 open surety bonds supporting future performance. The average face amount of these obligations is $4.6 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, 2014, approximately 55 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, 2014. In addition, ESG has an $8 million stand-alone letter of credit facility and as of March 31, 2014, $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. Laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects and other infrastructure improvement 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 included in the DRR. The order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $111 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $10.1 million and $9.3 million at March 31, 2014 and December 31, 2013, respectively. Due to the expiration of the initial five year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO approved a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order also approved an adjustment to the bill impact evaluation, limiting the resulting DRR rate per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals $187 million. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013.

Regulatory assets are expected to continue to increase in future periods as post in service carrying costs are recognized in the statement of income and operating costs are deferred. Given the extension of the DRR as discussed above and the growth in rate base that has occurred since the last rate case, the expected growth from the capital expenditure plan outlined above and the growth in the regulatory assets balance, it is anticipated that the Company will file a general rate case for the inclusion in rate base the above costs near the expiration of the DRR. As such, the rate increase limits discussed above are not expected to be reached given this capital expenditure plan during the five year time frame.

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. The legislation also allows for the 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 under this law, reflecting 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 small general service customer per month. In addition, the order approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its annual filing on April 30, 2014.

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 Condensed Consolidated Statements of Income currently. The recording of post in service carrying costs and depreciation 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. At March 31, 2014 and December 31, 2013, the Company has regulatory assets totaling $13.2 million and $12.1 million, respectively, associated with the deferral of depreciation and debt-related post in service carrying cost activities.

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.

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally mandated investment, and 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.

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.

While the Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation, it is expected that the law will 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.

Requests for Recovery Under Indiana Regulatory Mechanisms
The Company filed in November 2013 for authority to recover appropriate costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with existing pipeline safety regulations, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. The combined Vectren South and Vectren North Indiana filing requests recovery of the capital expenditures associated with the infrastructure replacement and improvement plan pursuant to the legislation, estimated to be approximately $865 million combined, inclusive of an estimated $30 million of possible economic development related expenditures, over the seven year period beginning in 2014. The plan also includes approximately $13 million of combined annual operating costs associated with pipeline safety rules. Intervening parties to the proceeding filed testimony that generally supports the Company's plan and the mechanism for recovery. A hearing in this proceeding was held May 8, 2014. An order is expected later in 2014.

Vectren South Electric Environmental Compliance Filing
On January 17, 2014, Vectren South filed a request with the IURC for approval of capital investments estimated to be between $70 million and $90 million on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2016. Roughly half of the investment will be made to control mercury in both air and water emissions. The remaining investment will be made to address EPA concerns on alleged increases in sulfur trioxide emissions. Although the Company believes these investments are recoverable as a federally mandated investment under Senate Bill 251, the Company has requested deferred accounting treatment in lieu of timely recovery to avoid immediate customer impacts. The accounting treatment request seeks deferral of depreciation and property tax expense related to these investments, accrual of post in service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The Company filed its case-in-chief on March 14, 2014, intervening parties are scheduled to file their testimony on May 21, 2014, and a hearing is scheduled for July 9, 2014.

Coal Procurement Procedures
Vectren South submitted a request for proposal (RFP) in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the Company’s last electric rate case, a sub docket proceeding was established to review the Company’s prospective coal procurement procedures. In March 2012, the IURC issued its order in that sub docket which concluded that Vectren South’s 2011 RFP process resulted in the lowest fuel cost reasonably possible. The IURC has, and will continue to, regularly monitor Vectren South’s procurement process in future fuel adjustment proceedings.

On December 5, 2011 within the quarterly FAC filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and will be recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer’s rates effective February 1, 2012. The total balance deferred for recovery through the Company’s FAC, starting February 2014, was $42.4 million, of which $40.6 million remains as of March 31, 2014.

Vectren South Electric Demand Side Management Program Filing
On August 16, 2010, Vectren South filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint

programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a

15

performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding discussed earlier. For the three months ended March 31, 2014, the Company recognized Electric revenue of $1.6 million associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ends electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's 2009 order. The legislation also allows for industrial customers to opt out of participating in future energy efficiency programs. Indiana's Governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company plans to file a request for Commission approval of a new portfolio of DSM programs by May 30, 2014 to be effective in January 2015.

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. A settlement in the case was reached between the IURC's pipeline safety division and Vectren North that allowed Vectren North to continue to use its risk based approach to inspecting excavations and to allow the Company to continue using a mix of highly trained and qualified contractors and employees to perform inspections. On January 15, 2014, the IURC issued a Final Order in the case approving the settlement agreement, without modification.

Vectren North & Vectren South Gas Decoupling Extension Filing

On August 18, 2011, the IURC issued an order granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015.

FERC Return on Equity Complaint

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. In the event a refund is required upon resolution of the complaint, the parties are seeking a refund calculated as of the filing date of the complaint. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. In addition to the group response, the Company filed a supplemental response, stating that if FERC allows the complaint to go forward, the complaint should not be applied to the Company's recently completed Gibson-Brown-Reid 345 Kv transmission line investment. As of March 31, 2014, the Company had invested approximately $157.6 million in qualifying projects. The net plant balance for these projects totaled $146.1 million at March 31, 2014.

FERC has no deadline for action. This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. In August 2013, a FERC administrative law judge recommended in that proceeding that the return be lowered to 9.7 percent, retroactive to the date of the complaint filing. The FERC has yet to rule on that case.

11. Legislative & Environmental Matters

Indiana Senate Bill 1
In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251
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 of 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, and in June 2013 the Supreme Court agreed to review the lower court decision. In April 2014, the US Supreme Court upheld the CSAPR. The EPA has yet to state its plans for implementation of the CSAPR since the Court's decision on April 29th. While it is possible that the EPA could revise the rule prior to implementation, the Company does not anticipate a significant impact from the Court's decision based upon the investments it has already made in pollution control technology to meet the requirements of CAIR. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Environmental Regulations").

Mercury and Air Toxics (MATS) Rule
On December 21, 2011, the EPA finalized the Utility MATS Rule. 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 electric generating 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). Multiple judicial challenges were filed and the EPA agreed to reconsider MATS requirements for new construction, as the 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. In April 2014, the U.S. Court of Appeals for the D.C. Circuit rejected various challenges to the rule for existing sources that were brought by industry and state petitioners. The Company continues to proceed with its MATS compliance strategy. This plan is currently before the IURC for approval, and the Company anticipates full compliance by the applicable deadlines.

Notice of Violation for A.B. Brown Power Plant

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 Selective Catalytic Reduction (SCR) systems, 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 provisions in effect when the equipment was installed, it is the Company's position that its SCR project was exempt from such requirements. The Company is currently in discussions with the EPA to resolve this NOV.

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 each state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in May 2014. 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 recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water 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 SCR systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with AGC (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 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 continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Some operational modifications to the control equipment are likely. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts. Currently, it is expected that the capital costs could be between $70 million and $90 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. On January 17, 2014, the Company filed its request with the IURC seeking approval to upgrade its existing emissions control equipment to comply with the MATS Rule, take steps to address EPA's allegations in the NOV and comply with new mercury limits to the waste water discharge permits at the Culley and Brown generating stations. In that filing, the Company has proposed to defer recovery of the costs until 2020 in order to mitigate the impact on customer rates in the near term.

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. Recently EPA entered into a consent decree in which it agreed to finalize by December 2014 its determination whether to regulate ash as hazardous waste, or the less stringent solid waste designation.

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 only 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 recoverable under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG 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 the EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two GHG regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory GHG 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 GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards (NSPS) for GHG's for new electric generating facilities under the Clean Air Act Section 111(b). On October 15, 2013, the US Supreme Court agreed to review a focused appeal on the issue of whether the GHG rule applicable to mobile sources triggered PSD permitting for all stationary sources such as Vectren's power plants. A decision is expected in 2014.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to re-propose and finalize the new source rule expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. The President's Climate Action Plan did not provide any detail as to actual emission targets or compliance requirements. 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. On May 6, 2014, the White House released a report on climate change and the impacts it has on regions within the United States, including the Midwest. The Company is currently assessing and evaluating the report to determine its impact to the Company.

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 GHG's 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 GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG 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 GHG 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 GHG emissions or expenditures made to control emissions should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana 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. 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 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. 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.

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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 $14.3 million of the expected $15.8 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, 2014 and December 31, 2013, approximately $5.2 million and $5.7 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 Guidance

Investments in Qualified Affordable Housing Projects

In January 2014, the FASB issued new accounting guidance on accounting for investments in qualified affordable housing projects. The amendments in this guidance allows an entity to make an accounting policy election to account for investments in qualified affordable housing projects using a proportional amortization method, if certain conditions are met. Under the election, the entity would amortize the initial cost of the investment in proportion to the tax credits and other benefits received while recognizing the net investment performance in the income statement as a component of income tax expense (benefit). The guidance is effective for annual periods and interim reporting periods within those annual periods, beginning after December 15, 2014, with early adoption permitted. The Company is assessing if its affordable housing investments will qualify for the election and whether or not it will choose to exercise the election. Adoption of this guidance will not have a material impact on the Company's financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company is currently evaluating the impact of this guidance, if any.

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, 2014		December 31, 2013	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$ 1,777.2	$ 1,917.2	$ 1,807.1	$ 1,895.2
Short-term borrowings	54.2	54.2	68.6	68.6
Cash & cash equivalents	54.5	54.5	21.5	21.5

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 nature of certain other 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, 2014 and December 31, 2013, the fair value for these financial instruments was not estimated. The carrying value of these investments was approximately $10.4 million at both March 31, 2014 and December 31, 2013, and is included in Other nonutility investments.

14. Long Lived Assets and Review for Impairment

Specific to the Company's investment in its owned coal mines, as a result of operating losses at the Company's Prosperity mine, resulting from higher production costs as a result of various factors, including poor mining conditions, and an overall decline in market prices for Illinois Basin coal, the Company performed a more detailed analysis to support the carrying value of that mine at December 31, 2013. Specifically, several third party-prepared price curves were obtained and were used to develop revenue forecasts for the remainder of the mine life, using estimated production volumes. Additionally, cost estimates were developed that considered prior actual costs, annualized current costs, and projected future costs. The various revenue scenarios were used in conjunction with estimated costs to derive estimated net operating cash flows for the remaining life of the mine. These estimates are highly subjective and may differ materially from actual results, but the results of the various analyses indicate that there is no impairment related to the Prosperity mine assets, at December 31, 2013. This analysis was updated at March 31, 2014 for changes in assumptions, estimates or actual data. The analysis continues to indicate that there is no impairment related to the Prosperity mine assets, at March 31, 2014.

15. 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 a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west-central Ohio. The Electric Utility Services segment provides electric distribution services primarily 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 has historically reported five segments: Infrastructure Services, Energy Services, Coal Mining, Energy Marketing, and Other Businesses. In 2013, ProLiance exited the energy marketing business. In its 2014 periodic reports, the Company reports the Energy Marketing segment information for 2013, which is inclusive of the Company's share of the loss from operations and its share of the loss on sale as recorded by ProLiance Energy.

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)	2014	2013
Revenues		
Utility Group		
Gas Utility Services	$443.6	$315.9
Electric Utility Services	163.0	149.5
Other Operations	9.6	9.5
Eliminations	(9.6)	(9.4)
Total Utility Group	606.6	465.5
Nonutility Group		
Infrastructure Services	123.0	171.8
Energy Services	17.5	20.5
Coal Mining	81.5	63.1
Total Nonutility Group	222.0	255.4
Corporate & Other Group	0.3	—
Eliminations	(32.1)	(20.3)
Consolidated Revenues	$796.8	$700.6
Profitability Measure - Net Income		
Utility Group Net Income		
Gas Utility Services	$38.3	$38.1
Electric Utility Services	19.3	14.6
Other Operations	3.7	2.4
Utility Group Net Income	61.3	55.1
Nonutility Group Net Income (Loss)		
Infrastructure Services	(5.3)	6.9
Energy Services	(3.0)	(1.4)
Coal Mining	(1.1)	(6.0)
Energy Marketing	—	(4.6)
Other Businesses	(0.3)	(0.3)
Nonutility Group Net Income (Loss)	(9.7)	(5.4)
Corporate & Other Group Net Income (Loss)	(0.4)	0.1
Consolidated Net Income	$51.2	$49.8

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 581,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 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 316,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is currently involved in nonutility activities in three primary business areas: Infrastructure Services, Energy Services, and Coal Mining. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining owns, and through its contract miners, mines and then sells coal. Enterprises supports the Company's regulated utilities by providing infrastructure services and coal. 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. Prior to June 18, 2013, the Company, through Enterprises, had activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance).

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 2013 annual report filed on Form 10-K.

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 Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. 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.

Results for the three months ended March 31, 2014 were earnings of $51.2 million, or $0.62 per share, compared to earnings of $49.8 million, or $0.61 per share for the three months ended March 31, 2013. In June 2013, ProLiance exited the gas marketing business through the disposition of certain of the net assets of its energy marketing subsidiary, ProLiance Energy, LLC. The Company is an equity method investor in ProLiance. In 2013, excluding the impact of the operating losses attributable to the

Company's investment in ProLiance, totaling $4.6 million, or $0.05 per share, consolidated net income for the quarter was $54.4 million, or $0.66 per share.

Consolidated Results Excluding the Results From ProLiance (See Page 26, regarding the Use of Non-GAAP Measures)

Net income and earnings per share, excluding results from ProLiance, in total and by group, for the three months ended March 31, 2014 and 2013 follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2014	2013
Net income, excluding ProLiance results	$51.2	$54.4
Attributed to:		
Utility Group	61.3	55.1
Nonutility Group, excluding ProLiance results	(9.7)	(0.8)
Corporate & other	(0.4)	0.1
Basic EPS, excluding ProLiance results	$0.62	$0.66
Attributed to:		
Utility Group	0.74	0.67
Nonutility Group, excluding ProLiance results	(0.12)	(0.01)

Utility Group

In the first quarter of 2014, the Utility Group earnings were $61.3 million, compared to $55.1 million in 2013. The 2014 increase is driven by customer growth, large customer usage, margin from Ohio infrastructure replacement programs, favorable interest and the impact of the colder than normal weather, offset somewhat by weather driven operating cost increases.

Gas Utility Services

During the first quarter of 2014, Gas Utility Services earned $38.3 million compared to earnings of $38.1 million in the first quarter of 2013. Though customer margin increased in 2014 from small customer growth and large customer usage, this increase was offset by increased operating expenses that were driven by weather-related maintenance of the gas system, including employee overtime.

Electric Utility Services

During the first quarter of 2014, Electric Utility Services' earnings were $19.3 million, compared to $14.6 million in the first quarter of 2013. Management estimates the impact of weather on retail electric margin to be approximately $3.5 million favorable in the first quarter of 2014 compared to first quarter 2013. The colder than normal weather also favorably impacted margin from wholesale operations, primarily due to higher prices. Earnings in 2014 were also favorably impacted by lower operating and interest expense.

Nonutility Group

The Nonutility group results for the first quarter of 2014 were a loss of $9.7 million, compared to a loss of $0.8 million in the prior year, excluding ProLiance. The larger loss in 2014 is primarily related to the favorable impacts of an eighty mile pipeline project on 2013 revenues and earnings and the effects of the adverse winter weather on working conditions in 2014 for pipeline construction and repair in the Infrastructure Services business area. To a lesser extent, the larger loss is also attributable to decreased Energy Services' earnings due to the expiration of tax deductions associated with energy efficiency projects as well as lagging backlog and new orders. Nonutility results in the quarter were favorably impacted by a lower loss at Coal Mining of $1.1 million in 2014, compared to a loss of $6.0 million in 2013. Coal Mining results during the quarter reflect an increase in tons produced and sold as well as the continued execution of cost improvement initiatives at the Prosperity Mine.

Dividends

Dividends declared for the three months ended March 31, 2014, were $0.360 per share, compared to $0.355 per share for the same period in 2013.

Use of Non-GAAP Performance Measures and Per Share Measures

Results Excluding ProLiance
This discussion and analysis contains non-GAAP financial measures that exclude the results related to ProLiance.

Management uses consolidated net income, consolidated earnings per share, and Nonutility Group net income, excluding results from ProLiance, to evaluate its results. Management believes analyzing underlying and ongoing business trends is aided by the removal of ProLiance results and the rationale for using such non-GAAP measures is that, through the disposition by ProLiance of certain ProLiance Energy assets, the Company has now exited the gas marketing business.

A material limitation associated with the use of these measures is that the measures that exclude ProLiance results do not include all costs recognized in accordance with GAAP. Management compensates for this limitation by prominently displaying a reconciliation of these non-GAAP performance measures to their closest GAAP performance measures. This display also provides financial statement users the option of analyzing results as management does or by analyzing GAAP results.

Contribution to Vectren's basic EPS
Per share earnings contributions of the Utility Group, Nonutility Group excluding ProLiance results, 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.

The following table reconciles consolidated net income, consolidated basic EPS, and Nonutility Group net income to those results excluding ProLiance results.

(In millions, except EPS)	Three Months Ended March 31, 2014		
	GAAP Measure	Add back ProLiance Losses	Non-GAAP Measure
Consolidated			
Net Income	$51.2	$—	$51.2
Basic EPS	$0.62	$—	$0.62
Nonutility Group Net Income (Loss)	$(9.7)	$—	$(9.7)

(In millions, except EPS)	Three Months Ended March 31, 2013		
	GAAP Measure	Add back ProLiance Losses	Non-GAAP Measure
Consolidated			
Net Income	$49.8	$4.6	$54.4
Basic EPS	$0.61	$0.05	$0.66
Nonutility Group Net Income (Loss)	$(5.4)	$4.6	$(0.8)

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 Condensed Consolidated Statements of Income.

Results of Operations of the Utility Group

The Utility Group is comprised of Utility Holdings' operations, which consist of the Company's regulated utility 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, 2014 and 2013, follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2014	2013
OPERATING REVENUES		
Gas utility	$443.6	$315.9
Electric utility	163.0	149.5
Other	—	0.1
Total operating revenues	606.6	465.5
OPERATING EXPENSES		
Cost of gas sold	270.9	157.2
Cost of fuel & purchased power	57.0	50.2
Other operating	98.3	86.8
Depreciation & amortization	49.9	48.4
Taxes other than income taxes	20.1	17.5
Total operating expenses	496.2	360.1
OPERATING INCOME	110.4	105.4
OTHER INCOME - NET	3.9	1.8
INTEREST EXPENSE	16.7	17.9
INCOME BEFORE INCOME TAXES	97.6	89.3
INCOME TAXES	36.3	34.2
NET INCOME	$61.3	$55.1
CONTRIBUTION TO VECTREN BASIC EPS	$0.74	$0.67

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.

In addition, the Company separately reflects 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. Following is a discussion and analysis of margin generated from regulated utility operations.

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)	2014	2013
Gas utility revenues	$443.6	$315.9
Cost of gas sold	270.9	157.2
Total gas utility margin	$172.7	$158.7
Margin attributed to:		
Residential & commercial customers	$123.2	$120.5
Industrial customers	18.8	17.3
Other	3.6	3.0
Regulatory expense recovery mechanisms	27.1	17.9
Total gas utility margin	$172.7	$158.7
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	65.6	55.1
Industrial customers	36.0	31.0
Total sold & transported volumes	101.6	86.1

Gas Utility margins were $172.7 million for the three months ended March 31, 2014, and compared to 2013, increased $14.0 million in the quarter. Customer margin increased $2.9 million compared to the first quarter of 2013 from small customer growth and large customer usage. Additionally, margin was favorably impacted $0.9 million by returns from infrastructure replacement programs, particularly in Ohio. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 122 percent of normal in Ohio and 115 percent of normal in Indiana during first quarter 2014, compared to 107 percent of normal in Ohio and 101 percent of normal in Indiana during 2013, had an approximate $0.4 million favorable impact on small customer margin. Weather was also the primary driver in the higher volumetric pass through costs, which increased $9.2 million compared to the prior year.

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)	2014	2013
Electric utility revenues	$163.0	$149.5
Cost of fuel & purchased power	57.0	50.2
Total electric utility margin	$106.0	$99.3
Margin attributed to:		
Residential & commercial customers	$64.3	$60.7
Industrial customers	26.0	26.1
Other	0.9	0.8
Regulatory expense recovery mechanisms	4.8	2.5
Subtotal: retail	$96.0	$90.1
Wholesale power & transmission system margin	10.0	9.2
Total electric utility margin	$106.0	$99.3
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	719.1	671.3
Industrial customers	660.1	659.3
Other customers	6.0	5.8
Total retail volumes sold	1,385.2	1,336.4

Retail

Electric retail utility margins were $96.0 million for the three months ended March 31, 2014, and, compared to 2013, increased by $5.9 million. Electric results are not protected by weather normalizing mechanisms which resulted in a $3.5 million increase in small customer margin as heating degree days in the first quarter of 2014 were 115 percent of normal compared to 101 percent of normal in 2013. Margin from regulatory expense recovery mechanisms increased $2.3 million in the first quarter of 2014 compared to first quarter of 2013 driven primarily by a corresponding increase in operating expenses associated with the electric state-mandated conservation programs.

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)	2014	2013
MISO Transmission system sales	$6.1	$6.6
MISO Off-system sales	3.9	2.6
Total wholesale margin	$10.0	$9.2

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $6.1 million and $6.6 million during the three months ended March 31, 2014 and 2013, respectively. As of March 31, 2014, the Company had invested approximately $157.6 million in qualifying projects. The net plant balance for these projects totaled $146.1 million at March 31, 2014. 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. Although currently being challenged as discussed below in Rate and Regulatory Matters, 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 $106.7 million that earned the FERC approved equity rate of return, including while under construction. The last segment of that project was placed into service in December 2012.

For the three months ended March 31, 2014, margin from off-system sales was $3.9 million, compared to $2.6 million for the three months ended March 31, 2013. 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 as well as an increase primarily related to weather.

Utility Group Operating Expenses

Other Operating

For the three months ended March 31, 2014, other operating expenses were $98.3 million, an increase of $11.5 million, compared to first quarter of 2013. Costs that are recovered directly in margin account for $8.4 million of the increase. Excluding these pass through costs, other operating expenses increased $3.1 million year to date, compared to the same period in 2013, primarily associated with increased energy delivery expenses due to the harsh winter weather in the first quarter 2014.

Depreciation & Amortization

In the first quarter of 2014, depreciation and amortization expense was $49.9 million, compared to $48.4 million in 2013. The increase reflects increased plant placed into service.

Taxes Other Than Income Taxes
For the first quarter of 2014, taxes other than income taxes were $20.1 million compared to $17.5 million for the period in 2013. The increase of $2.6 million is primarily due to higher revenue taxes associated with increased consumption and higher gas

costs. These taxes are primarily revenue-related taxes and 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. Laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects and other infrastructure improvement 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 included in the DRR. The order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $111 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $10.1 million and $9.3 million at March 31, 2014 and December 31, 2013, respectively. Due to the expiration of the initial five year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO approved a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order also approved an adjustment to the bill impact evaluation, limiting the resulting DRR rate per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals $187 million. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013.

Regulatory assets are expected to continue to increase in future periods as post in service carrying costs are recognized in the statement of income and operating costs are deferred. Given the extension of the DRR as discussed above and the growth in rate base that has occurred since the last rate case, the expected growth from the capital expenditure plan outlined above and the growth in the regulatory assets balance, it is anticipated that the Company will file a general rate case for the inclusion in rate base the above costs near the expiration of the DRR. As such, the rate increase limits discussed above are not expected to be reached given this capital expenditure plan during the five year time frame.

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. The legislation also allows for the 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 under this law, reflecting 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 small general service customer per month. In addition, the order approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its annual filing on April 30, 2014.

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 Condensed Consolidated Statements of Income currently. The recording of post in service carrying costs and depreciation 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. At March 31, 2014 and December 31, 2013, the Company has regulatory assets totaling $13.2 million and $12.1 million, respectively, associated with the deferral of depreciation and debt-related post in service carrying cost activities.

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.

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally mandated investment, and 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.

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.

While the Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation, it is expected that the law will 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.

Requests for Recovery Under Indiana Regulatory Mechanisms

The Company filed in November 2013 for authority to recover appropriate costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with existing pipeline safety regulations, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. The combined Vectren South and Vectren North Indiana filing requests recovery of the capital expenditures associated with the infrastructure replacement and improvement plan pursuant to the legislation, estimated to be approximately $865 million combined, inclusive of an estimated $30 million of possible economic development related expenditures, over the seven year period beginning in 2014. The plan also includes approximately $13 million of combined annual operating costs associated with pipeline safety rules. Intervening parties to the proceeding filed testimony that generally supports the Company's plan and the mechanism for recovery. A hearing in this proceeding was held May 8, 2014. An order is expected later in 2014.

Vectren South Electric Environmental Compliance Filing

On January 17, 2014, Vectren South filed a request with the IURC for approval of capital investments estimated to be between $70 million and $90 million on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2016. Roughly half of the investment will be made to control mercury in both air and water emissions. The remaining investment will be made to address EPA concerns on alleged increases in sulfur trioxide emissions. Although the

Company believes these investments are recoverable as a federally mandated investment under Senate Bill 251, the Company has requested deferred accounting treatment in lieu of timely recovery to avoid immediate customer impacts. The accounting treatment request seeks deferral of depreciation and property tax expense related to these investments, accrual of post in service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The Company filed its case-in-chief on March 14, 2014, intervening parties are scheduled to file their testimony on May 21, 2014, and a hearing is scheduled for July 9, 2014.

Coal Procurement Procedures
Vectren South submitted a request for proposal (RFP) in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the Company's last electric rate case, a sub docket proceeding was established to review the Company's prospective coal procurement procedures. In March 2012, the IURC issued its order in that sub docket which concluded that Vectren South's 2011 RFP process resulted in the lowest fuel cost reasonably possible. The IURC has, and will continue to, regularly monitor Vectren South's procurement process in future fuel adjustment proceedings.

On December 5, 2011 within the quarterly FAC filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and will be recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, starting February 2014, was $42.4 million, of which $40.6 million remains as of March 31, 2014.

Vectren South Electric Demand Side Management Program Filing
On August 16, 2010, Vectren South filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding discussed earlier. For the three months ended March 31, 2014, the Company recognized Electric revenue of $1.6 million associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ends electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's 2009 order. The legislation also allows for industrial customers to opt out of participating in future energy efficiency programs. Indiana's Governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company plans to file a request for Commission approval of a new portfolio of DSM programs by May 30, 2014 to be effective in January 2015.

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. A settlement in the case was reached between the IURC's pipeline safety division and Vectren North that allowed Vectren North to continue to use its risk based approach to inspecting excavations and to allow the Company to continue using a mix of highly trained and qualified contractors and employees to perform inspections. On January 15, 2014, the IURC issued a Final Order in the case approving the settlement agreement, without modification.

Vectren North & Vectren South Gas Decoupling Extension Filing
On August 18, 2011, the IURC issued an order granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015.

FERC Return on Equity Complaint
On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. In the event a refund is required upon resolution of the complaint, the parties are seeking a refund calculated as of the filing date of the complaint. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. In addition to the group response, the Company filed a supplemental response, stating that if FERC allows the complaint to go forward, the complaint should not be applied to the Company's recently completed Gibson-Brown-Reid 345 Kv transmission line investment. As of March 31, 2014, the Company had invested approximately $157.6 million in qualifying projects. The net plant balance for these projects totaled $146.1 million at March 31, 2014.

FERC has no deadline for action. This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. In August 2013, a FERC administrative law judge recommended in that proceeding that the return be lowered to 9.7 percent, retroactive to the date of the complaint filing. The FERC has yet to rule on that case.

Legislative & Environmental Matters

Indiana Senate Bill 1
In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251

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 of 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, and in June 2013 the Supreme Court agreed to review the lower court decision. In April 2014, the US Supreme Court upheld the CSAPR. The EPA has yet to state its plans for implementation of the CSAPR since the Court's decision on April 29th. While it is possible that the EPA could revise the rule prior to implementation, the Company does not anticipate a significant impact from the Court's decision based upon the investments it has already made in pollution control technology to meet the requirements of CAIR. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Environmental Regulations").

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the Utility MATS Rule. 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 electric generating 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). Multiple judicial challenges were filed and the EPA agreed to reconsider MATS requirements for new construction, as the 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. In April 2014, the U.S. Court of Appeals for the D.C. Circuit rejected various challenges to the rule for existing sources that were brought by industry and state petitioners. The Company continues to proceed with its MATS compliance strategy. This plan is currently before the IURC for approval, and the Company anticipates full compliance by the applicable deadlines.

Notice of Violation for A.B. Brown Power Plant

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 Selective Catalytic Reduction (SCR) systems, 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 provisions in effect when the equipment was installed, it is the Company's position that its SCR project was exempt from such requirements. The Company is currently in discussions with the EPA to resolve this NOV.

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 each state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in May 2014. 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 recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water 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 SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC (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 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 continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Some operational modifications to the control equipment are likely. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts. Currently, it is expected that the capital costs could be between $70 million and $90 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. On January 17, 2014, the Company filed its request with the IURC seeking approval to upgrade its existing emissions control equipment to comply with the MATS Rule, take steps to address EPA's allegations in the NOV and comply with new mercury limits to the waste water discharge permits at the Culley and Brown generating stations. In that filing, the Company has proposed to defer recovery of the costs until 2020 in order to mitigate the impact on customer rates in the near term.

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. Recently EPA entered into a consent decree in which it agreed to finalize by December 2014 its determination whether to regulate ash as hazardous waste, or the less stringent solid waste designation.

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 only 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 recoverable under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG 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 the EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two GHG regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory GHG 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 GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards (NSPS) for GHG's for new electric generating facilities under the Clean Air Act Section 111(b). On October 15, 2013, the US Supreme Court agreed to review a focused appeal on the issue of whether the GHG rule applicable to mobile sources triggered PSD permitting for all stationary sources such as Vectren's power plants. A decision is expected in 2014.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to re-propose and finalize the new source rule expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. The President's Climate Action Plan did not provide any detail as to actual emission targets or compliance requirements. 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. On May 6, 2014, the White House released a report on climate change and the impacts it has on regions within the United States, including the Midwest. The Company is currently assessing and evaluating the report to determine its impact to the Company.

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 GHG's 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 GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG 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 GHG emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including

37

allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana 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. 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 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. 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.

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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 $14.3 million of the expected $15.8 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, 2014 and December 31, 2013, approximately $5.2 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Results of Operations of the Nonutility Group

The Nonutility Group operates in three primary business areas: Infrastructure Services, Energy Services, and Coal Mining. Infrastructure Services provides underground pipeline construction and repair. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Coal Mining owns, and through its contract miners, mines and then sells coal. Enterprises supports the Company's regulated utilities by providing infrastructure services and coal. 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. Prior to June 18, 2013, the Company, through Enterprises, had activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance). Through ProLiance's exit of the gas marking business in 2013, the Company no longer has operating activities in the Energy Marketing business area. Nonutility Group earnings, excluding the results from ProLiance, for the three months ended March 31, 2014 and 2013 follow:

	Three Months Ended March 31,	
(In millions, except per share amounts)	2014	2013
NET INCOME (LOSS) EXCLUDING PROLIANCE RESULTS	$(9.7)	$(0.8)
CONTRIBUTION TO VECTREN BASIC EPS, EXCLUDING PROLIANCE RESULTS	$(0.12)	$(0.01)
NET INCOME (LOSS) ATTRIBUTED TO:		
Infrastructure Services	$(5.3)	$6.9
Energy Services	(3.0)	(1.4)
Coal Mining	(1.1)	(6.0)
Other Businesses	(0.3)	(0.3)

Including ProLiance results, the Nonutility Group results was a loss of $5.4 million for the three months ended March 31, 2013.

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, results of Infrastructure Services' operations for the first quarter of 2014 were a loss of $5.3 million, compared to earnings of $6.9 million for the same period in the prior year.

Revenues during the first quarter of 2014 were $123 million, compared to revenues of $172 million in 2013. In addition to the favorable impacts of an eighty mile pipeline project on 2013 revenues and earnings, the adverse winter weather, and even road restrictions, significantly lowered 2014 results due to the inability of work crews to complete their work as planned. However, it is expected that work that was delayed as a result of the adverse weather will be largely completed over the remainder of the year, along with other planned work, assuming the return of more typical weather and the current expectation of available trained work crews. Construction activity, generally, is expected to remain strong as aging natural gas and oil pipelines and related infrastructure are repaired and replaced. In addition, construction activity is expected to be favorably impacted as pipeline operators construct new pipelines due to the continued strong demand for new shale gas and oil infrastructure. At March 31, 2014, Infrastructure Services had an estimated backlog of $585 million. The estimated backlog at December 31, 2013 was $535 million. The backlog at March 31, 2014 and the return of more typical weather-related working conditions should allow Infrastructure Services results to be on plan for the year.

The backlog amounts above reflect estimates of revenues to be realized under blanket contracts. Projects included in backlog can be subject to delays or cancellation as a result of regulatory requirements, adverse weather conditions, and customer requirements, among other factors, which could cause actual revenue amounts to differ significantly from the estimates and/or revenues to be realized in periods other than originally expected.

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects through its wholly-owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' operated at a loss of $3.0 million during the three months ended March 31, 2014, compared to a loss of $1.4 million in 2013.

Though some positive indications are being seen in sales opportunities, the lower results in the first quarter of 2014 reflect lower revenues, which indicates continued slowness in demand for performance contracting projects due primarily to budgetary constraints at state, municipal, and school customers. The decrease in earnings also relates to the expiration of a temporary federal income tax incentive on December 31, 2013, that had provided deductions associated with certain energy efficiency projects for governmental customers. For the quarter ended, March 31, 2013, these tax deductions increased earnings by $0.6 million. At March 31, 2014, performance contracting backlog was $107 million, compared to $72 million on December 31, 2013.

On April 1, 2014, Energy Systems Group, acquired the federal sector energy services unit of Chevron Energy Solutions (CES), from Chevron USA. The base purchase price for the federal sector energy services unit of CES was approximately $24 million, with additional payments tied to specific contract transfers and new order targets in 2014 and 2015. The total purchase price could reach $49 million, when $200 million or more of new construction/engineering contracts are signed through 2015. Following the April 1, 2014 close, federal sector customers are now engaged in a contract assignment process, which is expected to be substantially complete in the first half of 2014. However, until the federal contracts are assigned, ESG will be performing all work through a Master Subcontract Agreement with CES and will receive all financial benefit associated with the contracts. See further discussion of Company issued guarantees and a Vectren Enterprises' indemnification associated with this acquisition in the Financial Condition section.

Separately, on March 24, 2014, ESG was awarded a $45 million contract for the design and construction of energy efficiency and infrastructure improvements at a water reclamation facility in Virginia.

ESG continues to develop strategies to position it for growth 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. This national focus is further evidenced by the President's announcement on May 9th of an additional $2 billion, which doubles the goal, for Federal Energy Efficiency performance contracting project spend through 2016.

Coal Mining

Coal Mining owns, and through its contract miners, mines and then sells 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 $1.1 million in the first quarter of 2014, compared to a loss of $6.0 million in the prior year.

Coal Mining revenues were $81.5 million in the first quarter 2014 compared to revenues of $63.1 million in first quarter 2013 primarily due to additional volumes sold of 0.3 million tons as well as an increased sales price per ton. While additional cost improvement measures are still being implemented at Prosperity mine, substantial progress was made in the second half of 2013 and continued into the first quarter of 2014. The execution of the revised mining plan has resulted in significant improvement in the production costs at this mine.

Vectren Fuels' expected production is approximately 7.3 million tons in 2014, compared to 6.2 million tons in 2013. Coal sales in 2014 are estimated at 7.6 million tons, compared to 6.2 million tons in 2013. The expected production increase in 2014 primarily relates to having a full year of operation at the second mine at the Company's Oaktown mining complex, which opened during the second quarter of 2013. The increased sales in 2014 include 0.3 million tons under contract carried over from 2013 that were not sold due to weather-related delivery issues. These tons were held in inventory at December 31, 2013. As of March 31, 2014, nearly all of the expected 2014 sales are committed and priced. Longer term, the Company continues to believe that there will be reduced coal volumes available from Central Appalachia due to increased regulation and that the large number of scrubbers to be installed throughout the United States, including the Midwest, should continue to 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, 2014, management estimates the Company’s total Illinois Basin coal reserves to be approximately 119.5 million tons. Vectren Fuels' three 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, 2014, the Company paid approximately $0.3 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.

A significant increase in the frequency and scope of MSHA inspections continues generally. Over the twelve month period ended March 31, 2014 and as a direct result of continued focus on safe work practices, citations issued by MSHA have decreased significantly. While there has been a reduction in overall citations, on October 11, 2013, a Prosperity mine contract employee was fatally injured. Additionally, on October 23 and October 29, 2013, there were a significant number of unwarrantable failure citations written at Prosperity mine. Through the contract miner and consistent with past practice, the Company intends to fully evaluate the citations written. The process of review, challenge and resolution of any assessment could be lengthy. However, MSHA no longer is required to wait for final orders of citations before relying on those citations to place a mine on a Pattern of Violation (POV) status. If in the future, Prosperity mine were placed on POV status, any future elevated citation written would result in the affected area of the mine being temporarily idled until the issue causing the citation is resolved. While under POV status, citations written would result in more frequent downtime of portions or all of the mine, resulting in higher costs of production. Following the receipt of a number of citations written in the fourth quarter of 2013, and in a continuing effort to address compliance with MSHA requirements, Prosperity is in the process of finalizing a Corrective Action Program (CAP) to be submitted to MSHA which includes a framework of meaningful measures to address the multiple citations, a change in mine management, increased management oversight in problem areas, increased manpower dedicated to these problem areas, and a timetable for achieving reductions

ProLiance

Disposition of ProLiance Energy
The Company has an investment in ProLiance, a nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets, along with the long-term pipeline and storage commitments, of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy), to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). Vectren's remaining investment in ProLiance relates primarily to ProLiance's investment in LA Storage, LLC (LA Storage). 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.

As a result of ProLiance exiting the natural gas marketing business on June 18, 2013, the Company recorded its share of the loss on the disposition, termination of long term pipeline and storage commitments, and related transaction and other costs totaling $43.6 million pre tax, or $26.8 million net of tax, during the second quarter of 2013.

In addition, in connection with the disposition, the Company and Citizens issued a guarantee to ETC. The guarantee issued by the Company and Citizens is a backup guarantee to the $50 million guarantee issued by ProLiance to ETC, and provides for a maximum guarantee of $25.0 million, or $15.3 million for the Company's 61 percent ownership share, and extends until June 2016. This guarantee will be called upon only in the event of default as defined in the asset sale agreement and only if the ProLiance guarantee is not sufficient to satisfy the relevant obligations. Although there can be no assurance that these guarantees will not be called upon, the Company believes that the likelihood that the Company or ProLiance will be called upon to satisfy any obligations pursuant to these guarantees is remote.

Pursuant to FERC approval, ETC ProLiance Energy has taken assignment of the Portfolio Administration Agreements (PAAs) pursuant to which the Company's utilities receive gas supply. ETC ProLiance Energy will fulfill the requirements of the PAAs through their remaining term ending in March 2016.

On March 19, 2014, Constellation Energy Group, LLC, a subsidiary of Exelon Corporation, announced it had reached an agreement to purchase ETC ProLiance Energy. That transaction did not change ETC ProLiance Energy’s obligations to fulfill the terms of the PAAs, nor did it terminate the Company's guarantee to ETC as described above.

LA Storage, LLC Storage Asset Investment
ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S 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 liquefied natural gas 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 the joint venture 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, the joint venture 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, 2014 and December 31, 2013, ProLiance’s investment in the joint venture was $35.6 million and $35.4 million, respectively.

The joint venture received a demand for arbitration from Williams Midstream Natural Gas Liquids, Inc. (“Williams”) in February 2011 related to a sublease agreement. Williams alleges that the joint venture was negligent in its attempt to convert certain salt caverns to natural gas storage and seeks damages of $56.7 million. The joint venture intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of March 31, 2014, 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

Investments in Qualified Affordable Housing Projects

In January 2014, the FASB issued new accounting guidance on accounting for investments in qualified affordable housing projects. The amendments in this guidance allows an entity to make an accounting policy election to account for investments in qualified affordable housing projects using a proportional amortization method, if certain conditions are met. Under the election, the entity would amortize the initial cost of the investment in proportion to the tax credits and other benefits received while recognizing the net investment performance in the income statement as a component of income tax expense (benefit). The guidance is effective for annual periods and interim reporting periods within those annual periods, beginning after December 15, 2014, with early adoption permitted. The Company is assessing if its affordable housing investments will qualify for the election and whether or not it will choose to exercise the election. Adoption of this guidance will not have a material impact on the Company's financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company is currently evaluating the impact of this guidance, if any.

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, 2014 approximated $520 million and $54 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 outstanding at March 31, 2014 approximated $875 million. As of March 31, 2014, Utility Holdings had no short-term borrowings outstanding and approximately $10 million of cash invested in money market funds. 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, 2014, was approximately $383 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.

Vectren Corporation's corporate credit rating is A-, as rated by Standard and Poor's Ratings Services (Standard and Poor's). Moody's Investor Services (Moody's) does not provide a rating for Vectren Corporation. The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at March 31, 2014, are A-/A2 as rated by Standard and Poor's and Moody's, respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings' commercial paper has a credit rating of A-2/P-1. 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 47 percent and 46 percent of long-term capitalization at March 31, 2014 and December 31, 2013, respectively. 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, 2014, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

The Company's A-/A2 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 recently acquired an energy services business and may expand its businesses through other acquisitions and/or joint venture investments. 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.

On March 11, 2014, a $30 million Vectren Capital senior unsecured note matured. The Series A note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.37 percent. The repayment of debt was funded from the Company's short-term credit facility.

Consolidated Short-Term Borrowing Arrangements

At March 31, 2014, 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. No borrowings were outstanding at March 31, 2014 for the Utility Group operations. As reduced by borrowings currently outstanding, approximately $196 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)	2014	2013	2014	2013
As of March 31				
Balance Outstanding	$—	$27.1	$54.2	$166.5
Weighted Average Interest Rate	n/a	0.36%	1.27%	1.35%
Quarterly Average - March 31				
Balance Outstanding	$1.9	$63.1	$25.9	$142.9
Weighted Average Interest Rate	0.26%	0.38%	1.29%	1.38%
Maximum Month End Balance Outstanding	$—	$75.1	$54.2	$166.5

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 $1.7 million and $2.3 million in the three months ended March 31, 2014 and 2013, respectively.

Potential Uses of Liquidity

Pension Funding Obligations

Currently, the Company anticipates making no contributions to its qualified pension plans in 2014.

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, 2014, parent level guarantees support a maximum of $25 million of Energy System Group’s (ESG) performance contracting commitments and warranty obligations and $45 million of other project guarantees.

On April 1, 2014, Energy Systems Group acquired the federal sector energy services unit of Chevron Energy Solutions (CES), from Chevron USA. Pursuant to the agreement, the acquisition includes a provision whereby Vectren Enterprises, Inc., another wholly owned subsidiary of the Company and the holding company for the Company's nonutility investments, provides CES with an indemnification for potential claims against the seller that could arise related to the performance of work undertaken by ESG. The acquisition includes ESG guarantees of performance under certain assumed contracts. The guarantees include energy savings that are used to satisfy project financing. The total maximum amount of the energy savings guarantees is approximately $150 million and will only be called upon in the event energy savings established under the existing contracts executed by CES are not achieved. The Company guarantees ESG’s performance under these energy savings guarantees. Further, an energy facility operated by ESG and managed by Keenan Ft Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Vectren Enterprises, Inc. provision providing indemnification to CES and the Company guarantee of the Keenan Ft Detrick Energy operations agreement with Keenan as discussed above, do not state a maximum guarantee. Due to the nature of work performed under these contracts, the Company cannot estimate a maximum potential amount of future payments.

As disclosed in Note 7, a guarantee issued and outstanding to an unrelated party in connection with ProLiance's disposition of certain of the net assets of ProLiance Energy totaled $15.3 million at March 31, 2014. In addition, the Company has approximately $25 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $19 million represent letters of credit supporting other nonutility operations.

While there can be no assurance that neither the Vectren Enterprises, Inc.'s indemnification nor the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

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, 2014, there are 50 open surety bonds supporting future performance. The average face amount of these obligations is $4.6 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, 2014, approximately 55 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, 2014. In addition, ESG has an $8 million stand-alone letter of credit facility and as of March 31, 2014, $3.4 million was drawn upon and outstanding.

Other Letters of Credit

As of March 31, 2014, 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, 2014.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at $310 million for the remainder of 2014. Nonutility capital expenditures and investments are estimated at $120 million for the remainder of 2014.

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 $182.0 million and $185.5 million for the three months ended March 31, 2014 and 2013, respectively. The slight decrease was driven by weather related impacts to working capital. As an example, compared to last year, fuel and natural gas costs billed to customers were higher than recoveries. This decrease was offset somewhat by other weather related changes in working capital.

Financing Cash Flow

Net cash flow required for financing activities was $72.4 million during the three months ended March 31, 2014 compared to requirements of $112.5 million in 2013. In the first quarter of 2014, $30 million in long-term debt was retired with funds from the Company's short-term credit facility. Financing activity in both periods presented reflects the payment of dividends and the repayment of short-term borrowings.

Investing Cash Flow

Cash flow required for investing activities was $76.6 million and $80.4 million during the three months ended March 31, 2014 and 2013, respectively. The primary use of cash in both periods presented reflect expenditures for utility and nonutility capital expenditures.

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 coal and natural gas 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, unbundling, and other sources of energy.

46

- 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 realize value from, invest in and develop new opportunities, including but not limited to, the Company’s infrastructure services, energy services, and coal mining, and remaining energy marketing assets.
- 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 and benefit 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 in a fast growing market where skills are critical; 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; geologic conditions, including coal seam thickness, 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.
- 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 2013 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, 2014, 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, 2014, 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, 2014, 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 condensed consolidated 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 2013 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, 2014.

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 12, 2014

/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
Senior Vice President, Finance and Assistant Treasurer
(Principal Accounting Officer)