

VECTREN UTILITY HOLDINGS INC
Form 10-Q
May 14, 2015

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2015
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: 1-16739

VECTREN UTILITY HOLDINGS, INC.
(Exact name of registrant as specified in its charter)

INDIANA
(State or other jurisdiction of incorporation or
organization)

35-2104850
(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. Yes No

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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).

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

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 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	10	April 30, 2015
Class	Number of Shares	Date

Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports, including those of its wholly owned subsidiaries, 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:

One Vectren Square
Evansville, Indiana 47708

Phone Number:
(812) 491-4000

Investor Relations Contact:

Robert L. Goocher
Treasurer and Vice President, Investor Relations
vvcir@vectren.com

Definitions

AFUDC: allowance for funds used during construction	MDth / MMDth: thousands / millions of dekatherms
DOT: Department of Transportation	MISO: Midcontinent Independent System Operator
EPA: Environmental Protection Agency	BTU / MMBTU: British thermal units/ millions of BTU
FAC: Fuel Adjustment Clause	MW: megawatts
FASB: Financial Accounting Standards Board	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FERC: Federal Energy Regulatory Commission	ASC: Accounting Standards Codification
IDEM: Indiana Department of Environmental Management	OUCC: Indiana Office of the Utility Consumer Counselor
GCA: Gas Cost Adjustment	XBRL: eXtensible Business Reporting Language
IURC: Indiana Utility Regulatory Commission	PUCO: Public Utilities Commission of Ohio
Kv: Kilovolt	

Throughput: combined gas sales and gas transportation volumes

MCF / BCF: thousands / billions of cubic feet

GAAP: Generally Accepted Accounting Principles

Table of Contents

Item Number		Page Number
	PART I. FINANCIAL INFORMATION	
1	<u>Financial Statements (Unaudited)</u> Vectren Utility Holdings, Inc. and Subsidiary Companies <u>Condensed Consolidated Balance Sheets</u> <u>Condensed Consolidated Statements of Income</u> <u>Condensed Consolidated Statements of Cash Flows</u> Notes to the <u>Condensed Consolidated Financial Statements (Unaudited)</u>	3- 4 <u>5</u> <u>6</u> <u>7</u>
2	<u>Management’s Discussion and Analysis of Results of Operations and Financial Condition</u>	<u>24</u>
3	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	<u>41</u>
4	<u>Controls and Procedures</u>	<u>41</u>
	PART II. OTHER INFORMATION	
1	<u>Legal Proceedings</u>	<u>42</u>
1A	<u>Risk Factors</u>	<u>42</u>
2	<u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	<u>42</u>
3	<u>Defaults Upon Senior Securities</u>	<u>42</u>
4	<u>Mine Safety Disclosures</u>	<u>42</u>
5	<u>Other Information</u>	<u>42</u>
6	<u>Exhibits</u>	<u>43</u>
	<u>Signatures</u>	<u>44</u>

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
 CONDENSED CONSOLIDATED BALANCE SHEETS
 (Unaudited – In millions)

	March 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash & cash equivalents	\$10.4	\$19.3
Accounts receivable - less reserves of \$5.3 & \$3.9, respectively	137.3	113.0
Accrued unbilled revenues	94.3	122.4
Inventories	86.8	113.2
Recoverable fuel & natural gas costs	—	9.8
Prepayments & other current assets	20.5	83.5
Total current assets	349.3	461.2
Utility Plant		
Original cost	5,778.0	5,718.7
Less: accumulated depreciation & amortization	2,316.9	2,279.7
Net utility plant	3,461.1	3,439.0
Investments in unconsolidated affiliates	0.2	0.2
Other investments	25.4	25.6
Nonutility plant - net	145.7	149.2
Goodwill - net	205.0	205.0
Regulatory assets	119.5	128.3
Other assets	17.8	19.6
TOTAL ASSETS	\$4,324.0	\$4,428.1

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
 CONDENSED CONSOLIDATED BALANCE SHEETS
 (Unaudited – In millions)

	March 31, 2015	December 31, 2014
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	\$132.2	\$180.4
Payables to other Vectren companies	19.7	28.6
Refundable fuel & natural gas costs	23.0	—
Accrued liabilities	148.6	122.3
Short-term borrowings	5.9	156.4
Current maturities of long-term debt	90.0	95.0
Total current liabilities	419.4	582.7
Long-Term Debt - Net of Current Maturities	1,162.4	1,162.3
Deferred Credits & Other Liabilities		
Deferred income taxes	696.4	685.1
Regulatory liabilities	417.1	410.3
Deferred credits & other liabilities	113.2	109.2
Total deferred credits & other liabilities	1,226.7	1,204.6
Commitments & Contingencies (Notes 8 - 11)		
Common Shareholder's Equity		
Common stock (no par value)	795.3	793.7
Retained earnings	720.2	684.8
Total common shareholder's equity	1,515.5	1,478.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	\$4,324.0	\$4,428.1

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
 CONDENSED CONSOLIDATED STATEMENTS OF INCOME
 (Unaudited – In millions)

	Three Months Ended March 31,	
	2015	2014
OPERATING REVENUES		
Gas utility	\$352.9	\$443.6
Electric utility	153.9	163.0
Other	0.1	—
Total operating revenues	506.9	606.6
OPERATING EXPENSES		
Cost of gas sold	172.0	270.9
Cost of fuel & purchased power	50.1	57.0
Other operating	102.8	98.3
Depreciation & amortization	52.1	49.9
Taxes other than income taxes	19.1	20.1
Total operating expenses	396.1	496.2
OPERATING INCOME	110.8	110.4
Other income - net	4.9	3.9
Interest expense	16.6	16.7
INCOME BEFORE INCOME TAXES	99.1	97.6
Income taxes	36.1	36.3
NET INCOME	\$63.0	\$61.3

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
 CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
 (Unaudited – In millions)

	Three Months Ended March 31,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	\$63.0	\$61.3
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	52.1	49.9
Deferred income taxes & investment tax credits	13.2	5.0
Expense portion of pension & postretirement periodic benefit cost	1.2	1.2
Provision for uncollectible accounts	3.1	1.6
Other non-cash items - net	1.4	0.9
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenue	0.7	(34.1)
Inventories	26.4	35.6
Recoverable/refundable fuel & natural gas costs	30.3	(24.2)
Prepayments & other current assets	60.4	26.8
Accounts payable, including to Vectren companies & affiliated companies	(51.7)	(18.4)
Accrued liabilities	28.8	39.7
Changes in noncurrent assets	12.7	13.3
Changes in noncurrent liabilities	(0.3)	(2.6)
Net cash provided by operating activities	241.3	156.0
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from additional capital contribution	1.6	1.6
Requirements for:		
Dividends to parent	(27.6)	(27.1)
Retirement of long-term debt	(5.0)	—
Net change in short-term borrowings	(150.5)	(28.6)
Net cash used in financing activities	(181.5)	(54.1)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	0.2	0.1
Requirements for capital expenditures, excluding AFUDC equity	(68.9)	(58.0)
Net cash used in investing activities	(68.7)	(57.9)
Net change in cash & cash equivalents	(8.9)	44.0
Cash & cash equivalents at beginning of period	19.3	8.6
Cash & cash equivalents at end of period	\$10.4	\$52.6

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), Southern Indiana Gas and Electric Company (SIGECO), 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. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to over 585,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to over 143,000 electric customers and over 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 over 317,000 natural gas customers located near Dayton in west central Ohio.

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, 2014, filed with the Securities and Exchange Commission on March 5, 2014, on Form 10-K. Because of the seasonal nature of the Company's utility 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. Subsidiary Guarantor and Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of Utility Holdings' \$350 million in short-term credit facilities, of which approximately \$6 million was outstanding at March 31, 2015, and Utility Holdings' has unsecured senior notes with a par value of \$875 million outstanding at March 31, 2015. The guarantees are full and unconditional and joint and several, and Utility Holdings has no direct subsidiaries other than the subsidiary guarantors. However, Utility Holdings does have operations other than those of the subsidiary guarantors. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors, which are 100 percent owned, separate from the parent company's operations is

required. Following are consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

7

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Condensed Consolidating Balance Sheet as of March 31, 2015 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	\$10.0	\$0.4	\$—	\$10.4
Accounts receivable - less reserves	137.3	—	—	137.3
Intercompany receivables	69.8	109.3	(179.1)	—
Accrued unbilled revenues	94.3	—	—	94.3
Inventories	86.7	0.1	—	86.8
Prepayments & other current assets	11.6	43.9	(35.0)	20.5
Total current assets	409.7	153.7	(214.1)	349.3
Utility Plant				
Original cost	5,778.0	—	—	5,778.0
Less: accumulated depreciation & amortization	2,316.9	—	—	2,316.9
Net utility plant	3,461.1	—	—	3,461.1
Investments in consolidated subsidiaries	—	1,452.3	(1,452.3)	—
Notes receivable from consolidated subsidiaries	—	746.5	(746.5)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.3	4.1	—	25.4
Nonutility plant - net	1.7	144.0	—	145.7
Goodwill - net	205.0	—	—	205.0
Regulatory assets	98.2	21.3	—	119.5
Other assets	28.8	1.6	(12.6)	17.8
TOTAL ASSETS	\$4,226.0	\$2,523.5	\$(2,425.5)	\$4,324.0
LIABILITIES & SHAREHOLDER'S EQUITY				
	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	\$127.4	\$4.8	\$—	\$132.2
Intercompany payables	12.8	0.7	(13.5)	—
Payables to other Vectren companies	19.7	—	—	19.7
Refundable fuel & natural gas costs	23.0	—	—	23.0
Accrued liabilities	165.7	17.9	(35.0)	148.6
Short-term borrowings	—	5.9	—	5.9
Intercompany short-term borrowings	22.4	69.1	(91.5)	—
Current maturities of long-term debt	15.0	75.0	—	90.0
Current maturities of long-term debt due to VUHI	74.1	—	(74.1)	—
Total current liabilities	460.1	173.4	(214.1)	419.4
Long-Term Debt				
Long-term debt	362.7	799.7	—	1,162.4
Long-term debt due to VUHI	746.5	—	(746.5)	—
Total long-term debt - net	1,109.2	799.7	(746.5)	1,162.4
Deferred Credits & Other Liabilities				
Deferred income taxes	668.5	27.9	—	696.4
Regulatory liabilities	415.6	1.5	—	417.1
Deferred credits & other liabilities	120.3	5.5	(12.6)	113.2
Total deferred credits & other liabilities	1,204.4	34.9	(12.6)	1,226.7
Common Shareholder's Equity				
Common stock (no par value)	808.5	795.3	(808.5)	795.3

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Retained earnings	643.8	720.2	(643.8) 720.2
Total common shareholder's equity	1,452.3	1,515.5	(1,452.3) 1,515.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	\$4,226.0	\$2,523.5	\$(2,425.5) \$4,324.0

8

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Condensed Consolidating Balance Sheet as of December 31, 2014 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	\$6.9	\$12.4	\$—	\$19.3
Accounts receivable - less reserves	113.0	—	—	113.0
Intercompany receivables	0.8	186.7	(187.5)	—
Accrued unbilled revenues	122.4	—	—	122.4
Inventories	113.2	—	—	113.2
Recoverable fuel & natural gas costs	9.8	—	—	9.8
Prepayments & other current assets	94.8	38.1	(49.4)	83.5
Total current assets	460.9	237.2	(236.9)	461.2
Utility Plant				
Original cost	5,718.7	—	—	5,718.7
Less: accumulated depreciation & amortization	2,279.7	—	—	2,279.7
Net utility plant	3,439.0	—	—	3,439.0
Investments in consolidated subsidiaries	—	1,416.9	(1,416.9)	—
Notes receivable from consolidated subsidiaries	—	746.5	(746.5)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.3	4.3	—	25.6
Nonutility plant - net	1.8	147.4	—	149.2
Goodwill - net	205.0	—	—	205.0
Regulatory assets	106.7	21.6	—	128.3
Other assets	29.4	1.7	(11.5)	19.6
TOTAL ASSETS	\$4,264.3	\$2,575.6	\$(2,411.8)	\$4,428.1
LIABILITIES & SHAREHOLDER'S EQUITY				
	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	\$176.2	\$4.2	\$—	\$180.4
Intercompany payables	15.6	0.8	(16.4)	—
Payables to other Vectren companies	28.6	—	—	28.6
Accrued liabilities	136.7	35.0	(49.4)	122.3
Short-term borrowings	—	156.4	—	156.4
Intercompany short-term borrowings	97.0	—	(97.0)	—
Current maturities of long-term debt	20.0	75.0	—	95.0
Current maturities of long-term debt due to VUHI	74.1	—	(74.1)	—
Total current liabilities	548.2	271.4	(236.9)	582.7
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	362.6	799.7	—	1,162.3
Long-term debt due to VUHI	746.5	—	(746.5)	—
Total long-term debt - net	1,109.1	799.7	(746.5)	1,162.3
Deferred Credits & Other Liabilities				
Deferred income taxes	665.8	19.3	—	685.1
Regulatory liabilities	408.8	1.5	—	410.3
Deferred credits & other liabilities	115.5	5.2	(11.5)	109.2
Total deferred credits & other liabilities	1,190.1	26.0	(11.5)	1,204.6
Common Shareholder's Equity				

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Common stock (no par value)	806.9	793.7	(806.9) 793.7
Retained earnings	610.0	684.8	(610.0) 684.8
Total common shareholder's equity	1,416.9	1,478.5	(1,416.9) 1,478.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	\$4,264.3	\$2,575.6	\$(2,411.8) \$4,428.1

9

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Condensed Consolidating Statement of Income for the three months ended March 31, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	\$352.9	\$—	\$—	\$352.9
Electric utility	153.9	—	—	153.9
Other	—	10.2	(10.1) 0.1
Total operating revenues	506.8	10.2	(10.1) 506.9
OPERATING EXPENSES				
Cost of gas sold	172.0	—	—	172.0
Cost of fuel & purchased power	50.1	—	—	50.1
Other operating	112.4	—	(9.6) 102.8
Depreciation & amortization	45.6	6.4	0.1	52.1
Taxes other than income taxes	18.7	0.4	—	19.1
Total operating expenses	398.8	6.8	(9.5) 396.1
OPERATING INCOME	108.0	3.4	(0.6) 110.8
Other income - net	4.1	10.8	(10.0) 4.9
Interest expense	15.9	11.3	(10.6) 16.6
INCOME BEFORE INCOME TAXES	96.2	2.9	—	99.1
Income taxes	36.7	(0.6) —	36.1
Equity in earnings of consolidated companies, net of tax	—	59.5	(59.5) —
NET INCOME	\$59.5	\$63.0	\$(59.5) \$63.0

Condensed Consolidating Statement of Income for the three months ended March 31, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	\$443.6	\$—	\$—	\$443.6
Electric utility	163.0	—	—	163.0
Other	—	9.6	(9.6) —
Total operating revenues	606.6	9.6	(9.6) 606.6
OPERATING EXPENSES				
Cost of gas sold	270.9	—	—	270.9
Cost of fuel & purchased power	57.0	—	—	57.0
Other operating	107.5	—	(9.2) 98.3
Depreciation & amortization	44.4	5.4	0.1	49.9
Taxes other than income taxes	19.6	0.4	0.1	20.1
Total operating expenses	499.4	5.8	(9.0) 496.2
OPERATING INCOME	107.2	3.8	(0.6) 110.4
Other income - net	3.0	10.7	(9.8) 3.9
Interest expense	15.8	11.3	(10.4) 16.7
INCOME BEFORE INCOME TAXES	94.4	3.2	—	97.6
Income taxes	36.8	(0.5) —	36.3
Equity in earnings of consolidated companies, net of tax	—	57.6	(57.6) —
NET INCOME	\$57.6	\$61.3	\$(57.6) \$61.3

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Condensed Consolidating Statement of Cash Flows for the three months ended March 31, 2015 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	\$240.6	\$0.7	\$—	\$241.3
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Additional capital contribution from parent	1.6	1.6	(1.6)	1.6
Requirements for:				
Dividends to parent	(25.8)	(27.6)	25.8	(27.6)
Retirement of long term debt	(5.0)	—	—	(5.0)
Net change in intercompany short-term borrowings	(74.6)	69.1	5.5	—
Net change in short-term borrowings	—	(150.5)	—	(150.5)
Net cash used in financing activities	(103.8)	(107.4)	29.7	(181.5)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	25.8	(25.8)	—
Other investing activities	—	0.2	—	0.2
Requirements for:				
Capital expenditures, excluding AFUDC equity	(64.6)	(4.3)	—	(68.9)
Consolidated subsidiary investments	—	(1.6)	1.6	—
Net change in short-term intercompany notes receivable	(69.1)	74.6	(5.5)	—
Net cash used in investing activities	(133.7)	94.7	(29.7)	(68.7)
Net change in cash & cash equivalents	3.1	(12.0)	—	(8.9)
Cash & cash equivalents at beginning of period	6.9	12.4	—	19.3
Cash & cash equivalents at end of period	\$10.0	\$0.4	\$—	\$10.4

Condensed Consolidating Statement of Cash Flows for the three months ended March 31, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	\$137.2	\$18.8	\$—	\$156.0
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	124.2	—	(124.2)	—
Additional capital contribution from parent	1.6	1.6	(1.6)	1.6
Requirements for:				
Dividends to parent	(25.4)	(27.1)	25.4	(27.1)
Net change in intercompany short-term borrowings	(73.1)	85.6	(12.5)	—
Net change in short-term borrowings	—	(28.6)	—	(28.6)
Net cash used in financing activities	27.3	31.5	(112.9)	(54.1)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	25.4	(25.4)	—
Other investing activities	—	0.1	—	0.1
Requirements for:				
Capital expenditures, excluding AFUDC equity	(51.3)	(6.7)	—	(58.0)
Consolidated subsidiary investments	—	(1.6)	1.6	—
Net change in long-term intercompany notes receivable	—	(124.2)	124.2	—

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Net change in short-term intercompany notes receivable	(85.6)	73.1	12.5	—
Net cash used in investing activities	(136.9)	(33.9)	112.9
Net change in cash & cash equivalents	27.6		16.4	—	44.0
Cash & cash equivalents at beginning of period	8.2		0.4	—	8.6
Cash & cash equivalents at end of period	\$35.8		\$16.8	\$—	\$52.6

11

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 \$11.7 million and \$12.9 million in the three months ended March 31, 2015 and 2014, respectively, as a component of operating revenues. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Supplemental Cash Flow Information

As of March 31, 2015 and December 31, 2014, the Company has accruals related to utility and nonutility plant purchases totaling approximately \$12.1 million and \$19.0 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Fuels, Inc. (Vectren Fuels)

On August 29, 2014, Vectren closed on a transaction to sell its wholly-owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy Company. Prior to the sale date, SIGECO purchased coal used for electric generation from Vectren Fuels. The Company purchased \$30.8 million for the three months ended March 31, 2014. After the exit of the coal mining business by Vectren, Sunrise has assumed Vectren Fuels' supply contracts and has also negotiated new contracts for similar quality coal that will result in the Company purchasing most of its coal supply from Sunrise.

Vectren Infrastructure Services Corporation (VISCO)

VISCO, a wholly owned subsidiary of Vectren, provides underground pipeline construction and repair services. VISCO's customers include Utility Holdings' utilities and fees incurred by Utility Holdings and its subsidiaries totaled \$17.7 million and \$11.4 million for the three months ended March 31, 2015 and 2014, respectively. Amounts owed to VISCO at March 31, 2015 and December 31, 2014 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Support Services & Purchases

Vectren provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. For the three months ended March 31, 2015 and 2014, Utility Holdings received corporate allocations totaling \$15.6 million and \$14.7 million, respectively.

The Company does not have share-based compensation plans and pension and other postretirement plans separate from Vectren and allocated costs include participation in Vectren's plans. The allocation methodology for retirement costs is consistent with FASB guidance related to "multiemployer" benefit accounting.

7. Financing Activities

Indiana Gas Unsecured Note Retirement

On March 15, 2015, a \$5.0 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15%. The repayment of debt was funded from the Company's short term credit facility.

8. Commitments & Contingencies

Commitments

The Company has both firm and non-firm commitments to purchase natural gas, electricity, and coal as well as certain transportation and storage rights. 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.

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.

9. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are a result of federal pipeline safety requirements. Laws in both Indiana and Ohio were passed that provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

In April 2011, Indiana Senate Bill 251 (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 is deferred for future recovery in the utility's next general rate case.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation supplements Senate Bill 251 described above, 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 current 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 is deferred and recovered in the utility's next general rate case, which must be filed before the expiration of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. By allowing for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

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 Indiana Gas and \$3 million annually at SIGECO. 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 SIGECO and four years after being placed into service at Indiana Gas. At March 31, 2015 and December 31, 2014, the Company has regulatory assets totaling \$17.3 million and \$16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company's seven-year capital

investment plan filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms

On August 27, 2014, the IURC issued an Order approving the Company's seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs,

inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company's next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company's proposal to recover eligible costs via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In April 2015, the Indiana Court of Appeals issued an opinion on an appeal involving Northern Indiana Public Service Company's (NIPSCO) infrastructure cost recovery mechanism finding that the value of retired assets should not be netted against the current recovery of costs. Although the opinion is specific to NIPSCO, the Company believes this decision is a positive outcome related to its pending appeal.

Additionally, in the NIPSCO appeal, the IURC's approval of the reasonableness of that infrastructure investment plan was challenged. The Court found that NIPSCO had failed to provide sufficient detail regarding its planned projects after year one of the plan to support the IURC's approval. An industrial group has asked the Court of Appeals to now consider that issue as part of the pending appeal of the Company's Order. Given this issue was never raised during the Company's IURC case or on appeal during the briefing period, the Company believes the opportunity to raise this issue has been waived and has asked the Court to strike the filing. The Court should decide these issues later this year.

On January 14, 2015, the IURC issued an Order approving the Company's initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate case. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company's update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost increases. The updated plan reflects capital expenditures of approximately \$900 million, an increase of \$35 million from the previous plan and is inclusive of an estimated \$30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately \$15 million of annual operating costs associated with pipeline safety rules.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. A procedural schedule has not been set in this proceeding. The Company expects an order in this proceeding mid-year in 2015.

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 \$156.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were \$14.2 million and \$13.1 million at March 31, 2015 and December 31, 2014, 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 issued an Order approving 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 limits the resulting DRR fixed charge 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 approximately \$200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however is not expected to exceed those caps. 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. On August 27, 2014 the PUCO issued an Order approving the Company's revised DRR rates and charges, effective September 1, 2014.

Given the extension of the DRR through 2017 as discussed above and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining three-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company's Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have 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. As of March 31, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company's capital expenditure program through calendar year 2014.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue

On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately \$3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC modified its position in testimony filed on November 5, 2014, and suggested a reduced disallowance of \$3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company's supply administrator was filed in this proceeding. Pending a final order from the IURC approving the stipulation, the agreement results in recovery of approximately \$1.4 million of the disputed amount via the Company's GCA mechanism, with the remaining \$1.6 million from the gas supply administrator.

Indiana Gas & SIGECO 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 Indiana gas companies and recovery of new conservation program costs through December 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing has been set for May 2015. The Company expects an order later in 2015.

10. Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing

On January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of March 31, 2015, approximately \$29 million has been spent on equipment to control mercury in both air and water emissions, and \$16 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total

investment is estimated to be between \$80 and \$90 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the 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 initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of March 31, 2015, the Company

has approximately \$0.7 million deferred related to depreciation, property tax, and operating expense, and \$0.3 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. Appellate briefs will be presented to the Court later in 2015 and it is expected the Court will decide on these issues in the second half of this year.

Coal Procurement Procedures

Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the IURC determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO 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 is being 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, which began February 2014, was \$42.4 million, of which \$33.6 million remains as of March 31, 2015.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011 the IURC issued an Order approving an initial three year DSM plan in the SIGECO 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. For the three months ended March 31, 2015 and 2014, the Company recognized Electric utility revenue of \$2.3 million and \$1.6 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the IURC's December 2009 Order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company's eligible industrial load has opted out of participation in the applicable energy efficiency programs. Indiana's governor has requested that the IURC 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 filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter 2015. On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy-efficiency plans to the IURC at least one time every

three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company will make its first filing pursuant to this bill in May 2015.

FERC Return on Equity (ROE) 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. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of March 31, 2015, the Company had invested approximately \$157.7 million in qualifying projects. The net plant balance for these projects totaled \$142.8 million at March 31, 2015.

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. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a methodology set out in its June 19, 2014 decision.

In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. A settlement has not been reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which defines a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order from the FERC is unknown at this time. The Company has established a reserve pending the outcome of this complaint.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

11. Environmental Matters

Indiana Senate Bill 251

Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations in addition to the impact on its gas utility operations. The Company continues with its ongoing evaluation of 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

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 SO2 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 SO2 and NOX allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA

finalized a new deadline schedule for entities that must comply, with CSAPR's first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

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. Reductions are to be achieved within three years of publication of the final rule in the Federal Register. 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. Legal challenges to the MATS Rule continue. In July, a coalition of twenty-one states, including Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. On November 25, 2014, the U.S. Supreme Court agreed to hear the case, with oral arguments completed, a decision is expected later in 2015. MATS compliance was required to commence April 16, 2015, and Company is in full compliance with all requirements of MATS.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that when the facility 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. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NO_x control on its units.

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on 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. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case by case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company's facilities. To comply, the Company believes that capital investments will likely be in the range of \$4 million to \$8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The 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. The 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 however the rule is not yet finalized. 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, 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. 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 SO₂ and 90 percent controlled for NOX.

Utilization of the Company's NOX and SO₂ 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.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between \$80 and \$90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds

In December 2014 the EPA released its final coal ash rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. Under the final rule the Company will be required to perform additional safety and structural assessments and an enhanced groundwater monitoring program to determine whether its existing ash ponds may remain in operation, be closed, or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from minor additional capital expenditures, if the ponds are permitted to continue to operate, and could exceed \$100 million if all existing ponds at both F.B. Culley and A.B. Brown generating stations must be closed and bottom ash conversions completed at each generating unit. The Company is in the process of evaluating the impact of this rule and any impact on its asset retirement obligation (ARO). It is expected that any 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 cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized two sets of 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, and in June 2014 the US Supreme Court upheld the regulations

with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal-fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO₂ emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO₂ emissions by 30 percent from 2005 levels by 2030. The EPA provided an extended time frame for public commentary to December 1, 2014. The proposal sets state-specific CO₂ emission rate-based CO₂ goals (measured in lb CO₂/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO₂/MWh, and sets an interim goal of 1,607 lb CO₂/MWh and a final emission goal of 1,531 lb CO₂/MWh that must be met by 2030. Under this proposal, these CO₂ emission rate goals do not apply directly to individual units, or generating systems. They instead are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. Indiana's interim or "phase in" goal of 1,607 lb CO₂/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal all states have unique goals based upon each state's mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana's total CO₂ emission rate compared to 2012. At 20 percent Indiana's CO₂ emission rate reduction requirement is tied with West Virginia as the 9th lowest reduction requirement. This is due in part to the EPA's attempt to recognize the existing generating resource mix in the state and take into account each state's ability to cost effectively lower its CO₂ emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA's determination of "Best System of Emission Reductions that has been adequately demonstrated," which defines the EPA's authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state's existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO₂ emission rate. The Company timely filed comments to the Clean Power Plan proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans. Oral arguments have been completed before the U.S. Court of Appeals for the D.C. Circuit, with a decision expected later in the summer.

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:

- (1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).
- (2) Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
- (3) Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
- (4) Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO₂ emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO₂ produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO₂. The Company's share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company's emissions of CO₂ have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of F.B. Culley

Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to renewable generation, 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 4 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. With respect to CO2 emission rate, since 2005 the Company has lowered its CO2 emission rate (as measured in lbs CO2/MWh) from 1967 lbs CO2/MWh to 1922 lbs CO2/MWh, for a reduction of 3 percent. The Company's CO2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO2 emission rate of 1923 lb CO2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO₂ 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 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 were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will continue to remain engaged with the state to develop a plan for compliance and have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates 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 or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

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 upon 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, 2015 and December 31, 2014, approximately \$3.5 million and \$3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

12. Fair Value Measurements

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

(In millions)	March 31, 2015		December 31, 2014	
	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	\$1,252.4	\$1,409.7	\$1,257.3	\$1,408.0
Short-term borrowings	5.9	5.9	156.4	156.4
Cash & cash equivalents	10.4	10.4	19.3	19.3

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities recorded at fair value outstanding, and no material assets or liabilities valued using Level 3 inputs.

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.

13. Impact of Recently Issued Accounting Principles

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the 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 adopted this guidance on January 1, 2015. The adoption of this guidance had no impact on the Company's financial

statements.

22

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016, and for annual and interim periods thereafter, with early adoption permitted. Adoption of this guidance will not have a material impact on the Company's financial statements.

Simplifying the Presentation of Debt Issuance Costs

In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted. The new guidance will be applied retrospectively to each prior period presented. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements. Adoption will have no impact on the Company's consolidated income statement.

14. Segment Reporting

The Company's operations consist of 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 Company is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other Shared Service 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.

(In millions)	Three Months Ended	
	March 31, 2015	2014
Revenues		
Gas Utility Services	\$352.9	\$443.6
Electric Utility Services	153.9	163.0
Other Operations	10.2	9.6
Eliminations	(10.1) (9.6
Total Revenues	\$506.9	\$606.6
Profitability Measure - Net Income		
Gas Utility Services	\$40.4	\$38.3
Electric Utility Services	19.2	19.3
Other Operations	3.4	3.7
Total Net Income	\$63.0	\$61.3

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

Description of the Business

Vectren Utility Holdings, Inc. (the Company, Utility Holdings, or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), Southern Indiana Gas and Electric Company (SIGECO), 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. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 585,000 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 317,000 natural gas customers located near Dayton in west central Ohio. The Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

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 2014 annual report filed on Form 10-K.

Executive Summary of Consolidated Results of Operations

In the first quarter of 2015, Utility Holdings' earnings were \$63.0 million, compared to \$61.3 million in 2014. The increase of \$1.7 million relates primarily to increases in gas utility margin from returns on the Indiana and Ohio infrastructure replacement programs.

Results of Operations

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:

(In millions)	Three Months Ended	
	March 31,	
	2015	2014
Gas utility revenues	\$352.9	\$443.6
Cost of gas sold	172.0	270.9
Total gas utility margin	\$180.9	\$172.7
Margin attributed to:		
Residential & commercial customers	\$126.3	\$123.2
Industrial customers	19.3	18.8
Other	3.4	3.6
Regulatory expense recovery mechanisms	31.9	27.1
Total gas utility margin	\$180.9	\$172.7
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	62.2	65.6
Industrial customers	38.0	36.0
Total sold & transported volumes	100.2	101.6

Gas Utility margins were \$180.9 million for the three months ended March 31, 2015, and compared to 2014, increased \$8.2 million in the quarter. Margin from small customer growth and large customer usage increased \$0.8 million compared to the first quarter of 2014. Additionally, margin was favorably impacted by the return from infrastructure replacement programs of \$1.6 million in Indiana and \$1.3 million in Ohio. Pass through margin increased \$4.8 million in 2015 compared to the first quarter 2014 due to regulatory expense recovery rate increases.

Electric Utility Margin (Electric utility revenues less Cost of fuel & purchased power)

Electric Utility margin and volumes sold by customer type follows:

(In millions)	Three Months Ended	
	March 31,	
	2015	2014
Electric utility revenues	\$153.9	\$163.0
Cost of fuel & purchased power	50.1	57.0
Total electric utility margin	\$103.8	\$106.0
Margin attributed to:		
Residential & commercial customers	\$63.7	\$64.3
Industrial customers	26.8	26.0
Other	1.0	0.9
Regulatory expense recovery mechanisms	3.3	4.8
Subtotal: retail	\$94.8	\$96.0
Wholesale power & transmission system margin	9.0	10.0
Total electric utility margin	\$103.8	\$106.0
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	702.6	719.1
Industrial customers	672.9	660.1
Other customers	6.1	6.0
Total retail volumes sold	1,381.6	1,385.2

Retail

Electric retail utility margins were \$94.8 million for the three months ended March 31, 2015, and, compared to 2014, decreased by \$1.2 million. Electric results, which are not protected by weather normalizing mechanisms, experienced a \$0.9 million decrease in small customer margin related to weather as annualized heating degree days in the first quarter of 2015 were 105 percent of normal compared to 108 percent of normal in 2014. As conservation initiatives continue, in the first quarter 2015 compared to first quarter 2014, the Company's lost revenue recovery mechanism contributed increased margin of \$0.6 million related to electric conservation programs. Margin from regulatory expense recovery mechanisms decreased \$1.5 million in 2015 compared to 2014, driven primarily by a corresponding decrease in operating expenses associated with the electric conservation programs. Additionally, results reflect an increase in large customer usage of \$0.6 million largely driven by an industrial customer coming on line in the Company's service territory in August 2014.

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:

(In millions)	Three Months Ended	
	March 31,	
	2015	2014
MISO Transmission system margin	\$6.5	\$6.1
MISO Off-system margin	2.5	3.9
Total wholesale margin	\$9.0	\$10.0

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled \$6.5 million and \$6.1 million during the three months ended March 31, 2015 and 2014, respectively. As of March 31, 2015, the Company had invested approximately \$157.7 million in qualifying projects. The net plant balance for these projects totaled \$142.8 million at March 31, 2015. These projects include an interstate 345 Kv

transmission line that connects the Company'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 the allowed return is 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. Operating expenses are also recovered. The Company has established a reserve pending the outcome of this complaint. The 345 Kv project is the largest of these qualifying projects, with a cost of \$106.8 million that earned the FERC approved equity rate of return, including while under construction.

For the three months ended March 31, 2015, margin from off-system sales was \$2.5 million, compared to \$3.9 million in 2014. 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 a decrease in volumes sold due to lower market pricing.

Operating Expenses

Other Operating

For the three months ended March 31, 2015, other operating expenses were \$102.8 million, an increase of \$4.5 million compared to 2014. The increase in other operating costs is primarily due to increases in costs that are recovered directly in margin. Excluding these pass through costs, other operating expenses decreased \$0.4 million in 2015, compared to the same period in 2014, primarily driven by decreased energy delivery expenses due to the harsh winter weather in the first quarter 2014.

Depreciation & Amortization

In the first quarter of 2015, depreciation and amortization expense was \$52.1 million, compared to \$49.9 million in 2014. The increase reflects increased plant placed in service.

Taxes Other Than Income Taxes

For the first quarter, taxes other than income taxes were \$19.1 million compared to \$20.1 million in 2014. The decrease of \$1.0 million is primarily due to decreased revenue taxes. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with lower gas utility and electric utility revenues reflected in margin attributable to regulatory expense recovery mechanisms.

Other Income - Net

Other income-net reflects income of \$4.9 million for the first quarter of 2015, an increase of \$1.0 million, compared to 2014. The increase is due to higher AFUDC driven by increased capital expenditures related to infrastructure replacement investments, as well as higher AFUDC rates.

Gas Rate & Regulatory Matters

The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are a result of federal pipeline safety requirements. Laws in both Indiana and Ohio were passed that provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

In April 2011, Indiana Senate Bill 251 (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 is deferred for future recovery in the utility's next general rate case.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation supplements Senate Bill 251 described above, 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 current 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 is deferred and recovered in the utility's next general rate case, which must be filed before the expiration of the seven year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. By allowing for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

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 Indiana Gas and \$3 million annually at SIGECO. 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 SIGECO and four years after being placed into service at Indiana Gas. At March 31, 2015 and December 31, 2014, the Company has regulatory assets totaling \$17.3 million and \$16.4 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company's seven-year capital investment plan filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms

On August 27, 2014, the IURC issued an Order approving the Company's seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company's next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company's proposal to recover eligible costs via a fixed monthly charge per residential customer.

On September 26, 2014, the OUCC filed an appeal of the IURC's finding that the remaining value of retired assets replaced during the infrastructure projects should not be netted against the cost being recovered in the tracking mechanism. In April 2015, the Indiana Court of Appeals issued an opinion on an appeal involving Northern Indiana Public Service Company's (NIPSCO) infrastructure cost recovery mechanism finding that the value of retired assets should not be netted against the current recovery of costs. Although the opinion is specific to NIPSCO, the Company believes this decision is a positive outcome related to its pending appeal.

Additionally, in the NIPSCO appeal, the IURC's approval of the reasonableness of that infrastructure investment plan was challenged. The Court found that NIPSCO had failed to provide sufficient detail regarding its planned projects after year one of the plan to support the IURC's approval. An industrial group has asked the Court of Appeals to now consider that issue as part of the pending appeal of the Company's Order. Given this issue was never raised during the

Company's IURC case or on appeal during the briefing period, the Company believes the opportunity to raise this issue has been waived and has asked the Court to strike the filing. The Court should decide these issues later this year.

On January 14, 2015, the IURC issued an Order approving the Company's initial request for recovery of the revenue requirement through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the

revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate case. Also, consistent with the guidelines set forth in the original August 2014 Order, the IURC approved the Company's update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost increases. The updated plan reflects capital expenditures of approximately \$900 million, an increase of \$35 million from the previous plan and is inclusive of an estimated \$30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately \$15 million of annual operating costs associated with pipeline safety rules.

On April 1, 2015, the Company filed its second request for recovery of the revenue requirement associated with capital investment and applicable operating costs through December 31, 2014. A procedural schedule has not been set in this proceeding. The Company expects an order in this proceeding mid-year in 2015.

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 \$156.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were \$14.2 million and \$13.1 million at March 31, 2015 and December 31, 2014, 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 issued an Order approving 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 limits the resulting DRR fixed charge 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 approximately \$200 million. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order however is not expected to exceed those caps. 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. On August 27, 2014 the PUCO issued an Order approving the Company's revised DRR rates and charges, effective September 1, 2014.

Given the extension of the DRR through 2017 as discussed above and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining three-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company's Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have 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. As of March 31, 2015, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company's capital expenditure program

through calendar year 2014.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue

On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately \$3.9 million of natural gas commodity purchases incurred during this period on the basis that a

gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC modified its position in testimony filed on November 5, 2014, and suggested a reduced disallowance of \$3 million. The IURC moved this specific issue to a sub-docket proceeding. On April 1, 2015, a stipulation and settlement agreement between the Company, the OUCC, and the Company's supply administrator was filed in this proceeding. Pending a final order from the IURC approving the stipulation, the agreement results in recovery of approximately \$1.4 million of the disputed amount via the Company's GCA mechanism, with the remaining \$1.6 million from the gas supply administrator.

Indiana Gas & SIGECO 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 Indiana gas companies and recovery of new conservation program costs through December 2015. The Companies have reached an agreement in principle with the OUCC to extend the decoupling mechanism through 2020. The settlement was filed for approval on March 1, 2015. The settlement was unopposed and a hearing has been set for May 2015. The Company expects an order later in 2015.

Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing

On January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. As of March 31, 2015, approximately \$29 million has been spent on equipment to control mercury in both air and water emissions, and \$16 million to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. The total investment is estimated to be between \$80 and \$90 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the 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 initial phase of the projects went into service in 2014, with the remaining investment expected to occur in 2015 and 2016. As of March 31, 2015, the Company has approximately \$0.7 million deferred related to depreciation, property tax, and operating expense, and \$0.3 million deferred related to post-in-service carrying costs.

In March 2015, the Company was notified that certain parties had filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. Appellate briefs will be presented to the Court later in 2015 and it is expected the Court will decide on these issues in the second half of this year.

Coal Procurement Procedures

Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the IURC determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO 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 is being 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, which began February 2014, was \$42.4 million, of which \$33.6 million remains as of March 31, 2015.

SIGECO Electric Demand Side Management (DSM) Program Filing

On August 31, 2011 the IURC issued an Order approving an initial three year DSM plan in the SIGECO 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. For the three months ended March 31, 2015 and 2014, the Company recognized Electric utility revenue of \$2.3 million and \$1.6 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the IURC's December 2009 Order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company's eligible industrial load has opted out of participation in the applicable energy efficiency programs. Indiana's governor has requested that the IURC 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 filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs were implemented during the first quarter 2015. On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 into law requiring electricity suppliers to create and submit energy-efficiency plans to the IURC at least one time every three years. Senate Bill 412 also supports the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company will make its first filing pursuant to this bill in May 2015.

FERC Return on Equity (ROE) 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. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of March 31, 2015, the Company had invested approximately \$157.7 million in qualifying projects. The net plant balance for these projects totaled \$142.8 million at March 31, 2015.

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. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a methodology set out in its June 19, 2014 decision.

In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. A settlement has not been reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which defines a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order

from the FERC is unknown at this time. The Company has established a reserve pending the outcome of this complaint.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

Environmental Matters

Indiana Senate Bill 251

Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations in addition to the impact on its gas utility operations. The Company continues with its ongoing evaluation of 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

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 SO2 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 SO2 and NOX allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA finalized a new deadline schedule for entities that must comply, with CSAPR's first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

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. Reductions are to be achieved within three years of publication of the final rule in the Federal Register. 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. Legal challenges to the MATS Rule continue. In July, a coalition of twenty-one states, including Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. On November 25, 2014, the U.S. Supreme Court agreed to hear the case, with oral arguments completed, a decision is expected later in 2015. MATS compliance was required to commence April 16, 2015, and Company is in full compliance with all requirements of MATS.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that when the facility 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. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level with the range of 65 to 70 ppb. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NO_x control on its units.

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts on 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. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a state level case by case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company’s facilities. To comply, the Company believes that capital investments will likely be in the range of \$4 million to \$8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The 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. The 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 however the rule is not yet finalized. 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, 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. SCR technology is the most effective method of reducing NO_x 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 SO₂ and 90 percent controlled for NO_x.

Utilization of the Company’s NO_x and SO₂ 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.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between \$80 and \$90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds

In December 2014 the EPA released its final coal ash rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. Under the final rule the Company will be required to perform additional safety and structural assessments and an enhanced groundwater monitoring program to determine whether its existing ash ponds may

remain in operation, be closed, or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states.

Under the final CCR rule, the Company is required to complete a series of integrity assessments and groundwater monitoring studies to determine whether one or more of the Company's ash ponds can continue in service, or whether a pond must be

retrofitted with liners or closed and bottom ash handling conversions completed. The Company estimates capital expenditures to comply with the alternatives in the final rule could range from minor additional capital expenditures, if the ponds are permitted to continue to operate, and could exceed \$100 million if all existing ponds at both F.B. Culley and A.B. Brown generating stations must be closed and bottom ash conversions completed at each generating unit. The Company is in the process of evaluating the impact of this rule and any impact on its asset retirement obligation (ARO). It is expected that any costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change

As a wholly owned subsidiary of Vectren, Utility Holdings is committed to responsible environmental stewardship and conservation efforts and if a national climate change policy is implemented believes it should have the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to base load generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for investment in advanced clean coal technology and support for research and development; and
- A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company's direct CO₂ emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA's e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions

The Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Focusing the Company's mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report received C level certification by the Global Reporting Initiative. This certification creates shared value, demonstrates the Company's commitment to sustainability and denotes transparency in operations;
- Implementing conservation initiatives in the Company's Indiana and Ohio gas utility service territories;
- Implementing conservation and demand side management initiatives in the electric service territory;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans; and
- Reducing the Company's carbon footprint by measures such as utilizing hybrid vehicles and optimizing generation efficiencies by utilizing dense pack technology

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 cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the

environment.

The EPA has finalized two sets of 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.

34

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, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal-fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO₂ emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO₂ emissions by 30 percent from 2005 levels by 2030. The EPA provided an extended time frame for public commentary to December 1, 2014. The proposal sets state-specific CO₂ emission rate-based CO₂ goals (measured in lb CO₂/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO₂/MWh, and sets an interim goal of 1,607 lb CO₂/MWh and a final emission goal of 1,531 lb CO₂/MWh that must be met by 2030. Under this proposal, these CO₂ emission rate goals do not apply directly to individual units, or generating systems. They instead are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. Indiana's interim or "phase in" goal of 1,607 lb CO₂/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal all states have unique goals based upon each state's mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana's total CO₂ emission rate compared to 2012. At 20 percent Indiana's CO₂ emission rate reduction requirement is tied with West Virginia as the 9th lowest reduction requirement. This is due in part to the EPA's attempt to recognize the existing generating resource mix in the state and take into account each state's ability to cost effectively lower its CO₂ emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA's determination of "Best System of Emission Reductions that has been adequately demonstrated," which defines the EPA's authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state's existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO₂ emission rate. The Company timely filed comments to the Clean Power Plan proposal on December 1, 2014. The State of Indiana also filed public comments, asking that the proposal be withdrawn. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans. Oral arguments have been completed before the U.S. Court of Appeals for the D.C. Circuit, with a decision expected later in the summer.

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:
(1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).

- (2)Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
- (3)Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
- (4)Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO2 emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO2. The

Company's share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company's emissions of CO₂ have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to renewable generation, 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 4 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. With respect to CO₂ emission rate, since 2005 the Company has lowered its CO₂ emission rate (as measured in lbs CO₂/MWh) from 1967 lbs CO₂/MWh to 1922 lbs CO₂/MWh, for a reduction of 3 percent. The Company's CO₂ emission rate of 1922 lbs/MWh is basically the same as the State's average CO₂ emission rate of 1923 lb CO₂/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO₂ 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 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 were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will continue to remain engaged with the state to develop a plan for compliance and have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates 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 or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

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 upon 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, 2015 and December 31, 2014, approximately \$3.5 million and \$3.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the 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 adopted this guidance on January 1, 2015. The adoption of this guidance had no impact on the Company's financial statements.

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016, and for annual and interim periods thereafter, with early adoption permitted. Adoption of this guidance will not have a material impact on the Company's financial statements.

Simplifying the Presentation of Debt Issuance Costs

In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will

continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted. The new guidance will be applied retrospectively to each prior period presented. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements. Adoption will have no impact on the Company's consolidated income statement.

Financial Condition

Utility Holdings funds the short-term and long-term financing needs of its utility subsidiary operations. Vectren does not guarantee Utility Holdings' debt. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. The guarantees are full and unconditional and joint and several, and Utility Holdings has no direct subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 3 to the consolidated financial statements. Utility Holdings' long-term debt, including current maturities, outstanding at March 31, 2015 approximated \$875 million. As of March 31, 2015, Utility Holdings had \$6 million in short-term borrowings outstanding. 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, 2015, was approximately \$377 million. Utility Holdings' operations have historically been the primary funding source for Vectren's common stock dividends.

The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at March 31, 2015, are A-/A2 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. The credit ratings on SIGECO's secured debt are A/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 50-60 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 55 percent of long-term capitalization at March 31, 2015 and 54 percent at December 31, 2014. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholder's 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, 2015, the Company was in compliance with all debt covenants.

Available Liquidity

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 supplemented with incremental external debt financing. 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; and expanded EPA regulations for air, water, and fly ash. These regulations may result in the need to raise additional debt and equity capital in the coming years.

On May 12, 2015 Utility Holdings priced \$200 million of its senior unsecured notes to be issued in three tranches of 20, 30, and 40 years. The notes were sold to various institutional investors through the private placement market and subject to the satisfaction of customary closing conditions, the notes will be issued on or about December 15, 2015.

Utility Holdings will be issuing \$25 million of 3.90% Series A senior notes due December 15, 2035, \$135 million of 4.36% Series B senior notes due December 15, 2045, and \$40 million of 4.51% Series C senior notes due December 15, 2055.

On March 15, 2015, a \$5.0 million Indiana Gas senior unsecured note matured. The Series E note carried a fixed interest rate of 7.15%. The repayment of debt was funded from the Company's short-term credit facility.

Consolidated Short-Term Borrowing Arrangements

At March 31, 2015, the Company has \$350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately \$344 million was available at March 31, 2015. This short-term credit facility was amended on October 31, 2014 to, among other things, extend the maturity until October 31, 2019. The maximum limit of the facility remained unchanged. This facility is 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 its short-term borrowing needs through the commercial paper market and expects to use the short-term borrowing facility in instances where the commercial paper market is not efficient.

Following is certain information regarding these short-term borrowing arrangements.

(In millions)	2015	2014
As of March 31		
Balance Outstanding	\$5.9	\$—
Weighted Average Interest Rate	0.39%	n/a
Quarterly Average - March 31		
Balance Outstanding	\$69.2	\$1.9
Weighted Average Interest Rate	0.39%	0.26%
Maximum Month End Balance Outstanding	\$121.5	\$—

Potential Uses of Liquidity

Pension Funding Obligations

For the three months ended March 31, 2015, Vectren contributed \$20 million to its qualified pension plans. Utility Holdings may fund a portion of the total contribution as it relates to its plans. Vectren does not anticipate making further contributions in 2015.

Planned Capital Expenditures

Capital expenditures are estimated at \$350 million for the remainder of 2015.

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 \$241.3 million and \$156.0 million for the three months ended March 31, 2015 and 2014, respectively. The increase is driven primarily by certain weather related impacts to working capital accounts. Weather related impacts include the fluctuation in the recoverable/refundable natural gas and fuel costs, accounts receivable, and accounts payable. Additionally, a decrease in prepaid taxes was due to a federal refund received in 2015 related to the extension of bonus depreciation in 2014.

Financing Cash Flow

Net cash flow required for financing activities was \$181.5 million and \$54.1 million during the three months ended March 31, 2015 and 2014, respectively. The current year period, compared to first quarter of 2014, reflects a greater decrease of short term borrowings of \$121.9 million. Financing activity in both periods presented reflects the payment of dividends.

Investing Cash Flow

Cash flow required for investing activities was \$68.7 million and \$57.9 million during the three months ended March 31, 2015 and 2014, respectively. The primary use of cash in both periods presented reflect expenditures for utility 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 the Company's facilities, operations, financial condition, results of operations, and reputation.

Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.

Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under 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, and other nonutility products and services; impacts on both gas and electric large customers; lower residential and commercial customer counts; and higher operating expenses.

Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.

Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.

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.

- 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 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 federal and state laws and interpretations of these laws.

40

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 Utility Holdings, Inc. 2014 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, 2015, 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, 2015, 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, 2015, 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. OTHER INFORMATION

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, rate and regulatory matters. The condensed consolidated financial statements are included in Part 1 Item 1.

During the third quarter of 2014, the Company was notified of claims by a group of current and former SIGECO employees (“claimants”) who participated in the Pension Plan for Salaried Employees of SIGECO (“SIGECO Salaried Plan”). That plan was merged into the Vectren Corporation Combined Non-Bargaining Retirement Plan (“Vectren Combined Plan”) effective July 1, 2000. The claims relate to the claimants’ election for benefits to be calculated under the Vectren Combined Plan’s cash-balance formula rather than the SIGECO Salaried Plan formula in effect prior to the formation of Vectren. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan and the Company in federal district court requesting that a class be certified and for various relief including that the Combined Plan be reformed and benefits thereunder be recalculated. The Company denied the allegations set forth in the Complaint.

The Company is unable to quantify any potential impact of the claims. The Company does not expect, however, the outcome would have a material adverse effect on the Company’s liquidity, results of operations or financial condition.

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 Utility Holdings 2014 Form 10-K and are therefore not presented herein.

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

Not Applicable

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

- 10.1 Grant Agreement for Non-Employee Director Stock Grant, dated January 1, 2015. (Filed and designated in Form 8-K, dated January 2, 2015, File No. 1-16739, as Exhibit 10.1)
- 10.2 Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed in Form 10-Q herewith as Exhibit 10.2.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission.
- 10.3 Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed in Form 10-Q herewith as Exhibit 10.3.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission.
- 10.4 Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed in Form 10-Q herewith as Exhibit 10.4.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission.
- 10.5 First Amendment to the Vectren Corporation At Risk Compensation Plan (as amended and restated May 1, 2011) (filed and designated in Form 8-K, dated February 9, 2015, File No. 1-16739, as Exhibit 99.1)
- 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
- 99.1 Code of By-Laws of Vectren corporation as Most Recently Amended as of March 4, 2015 (filed and designated in Form 8-K, dated March 10, 2015, File No. 1-16739, as Exhibit 3.1)
- 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

43

SIGNATURES

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

VECTREN UTILITY HOLDINGS, INC.
Registrant

May 14, 2015

/s/M. Susan Hardwick
M. Susan Hardwick
Senior Vice President and Chief Financial Officer
(Signing on behalf of the registrant and as Principal Accounting &
Financial Officer)