VECTREN UTILITY HOLDINGS INC
Form 10-Q
November 14, 2013

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013
OR

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

For the transition period from __________________ to __________________

Commission file number: 1-16739

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

INDIANA	35-2104850
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
ý Yes o 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 o	Accelerated filer o
Non-accelerated filer ý (Do not check if a smaller reporting company)	Smaller reporting company o

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

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

Common Stock- Without Par Value	10	October 31, 2013
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:	Phone Number:	Investor Relations Contact:
One Vectren Square Evansville, Indiana 47708	(812) 491-4000	Robert L. Goocher Treasurer and Vice President, Investor Relations rgoocher@vectren.com

Definitions

AFUDC: allowance for funds used during construction	MISO: Midcontinent Independent System Operator (formerly Midwest Independent System Operator)
DOT: Department of Transportation	MMBTU: millions of British thermal units
EPA: Environmental Protection Agency	MW: megawatts
FAC: Fuel Adjustment Clause	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FASB: Financial Accounting Standards Board	OCC: Ohio Office of the Consumer Counselor
FERC: Federal Energy Regulatory Commission	OUCC: Indiana Office of the Utility Consumer Counselor
IDEM: Indiana Department of Environmental Management	PUCO: Public Utilities Commission of Ohio
IURC: Indiana Utility Regulatory Commission	Throughput: combined gas sales and gas transportation volumes
MCF / BCF: thousands / billions of cubic feet	XBRL: eXtensible Business Reporting Language
MDth / MMDth: thousands / millions of dekatherms	

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash & cash equivalents	$6.2	$13.3
Accounts receivable - less reserves of $4.3 & $5.0, respectively	69.9	81.8
Accrued unbilled revenues	33.1	93.6
Inventories	98.5	114.0
Recoverable fuel & natural gas costs	19.5	25.3
Prepayments & other current assets	54.1	52.3
Total current assets	281.3	380.3
Utility Plant		
Original cost	5,326.9	5,176.8
Less: accumulated depreciation & amortization	2,136.3	2,057.2
Net utility plant	3,190.6	3,119.6
Investments in unconsolidated affiliates	0.2	0.2
Other investments	32.6	32.6
Nonutility plant - net	143.5	146.9
Goodwill - net	205.0	205.0
Regulatory assets	135.4	126.5
Other assets	27.4	35.7
TOTAL ASSETS	$4,016.0	$4,046.8

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

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

	September 30, 2013	December 31, 2012
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$96.2	$121.0
Accounts payable to affiliated companies	—	29.7
Payables to other Vectren companies	23.1	25.1
Accrued liabilities	103.2	139.3
Short-term borrowings	176.1	116.7
Current maturities of long-term debt	—	105.0
Total current liabilities	398.6	536.8
Long-Term Debt - Net of Current Maturities	1,107.0	1,103.4
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	627.2	578.5
Regulatory liabilities	381.9	364.2
Deferred credits & other liabilities	81.0	73.9
Total deferred credits & other liabilities	1,090.1	1,016.6
Commitments & Contingencies (Notes 8 - 10)		
Common Shareholder's Equity		
Common stock (no par value)	786.1	781.6
Retained earnings	634.2	608.4
Total common shareholder's equity	1,420.3	1,390.0
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,016.0	$4,046.8

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
OPERATING REVENUES				
Gas utility	$101.9	$100.2	$555.8	$508.5
Electric utility	165.8	167.9	470.0	456.6
Other	—	(0.4)	0.2	0.5
Total operating revenues	267.7	267.7	1,026.0	965.6
OPERATING EXPENSES				
Cost of gas sold	27.5	28.1	235.4	197.0
Cost of fuel & purchased power	50.4	52.9	154.5	144.6
Other operating	74.0	71.8	236.9	229.5
Depreciation & amortization	49.7	46.3	146.8	142.7
Taxes other than income taxes	11.6	11.5	41.3	39.0
Total operating expenses	213.2	210.6	814.9	752.8
OPERATING INCOME	54.5	57.1	211.1	212.8
Other income - net	2.0	2.3	6.8	5.2
Interest expense	15.6	17.8	49.2	53.5
INCOME BEFORE INCOME TAXES	40.9	41.6	168.7	164.5
Income taxes	15.6	15.2	64.1	62.0
NET INCOME	$25.3	$26.4	$104.6	$102.5

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

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

	Nine Months Ended September 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$104.6	$102.5
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	146.8	142.7
Deferred income taxes & investment tax credits	27.9	38.1
Expense portion of pension & postretirement periodic benefit cost	4.2	3.4
Provision for uncollectible accounts	4.8	5.9
Other non-cash expense - net	4.7	4.8
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenue	67.7	97.1
Inventories	15.5	14.1
Recoverable/refundable fuel & natural gas costs	5.8	(7.9)
Prepayments & other current assets	4.3	10.3
Accounts payable, including to Vectren companies & affiliated companies	(64.0)	(52.4)
Accrued liabilities	(16.5)	(17.3)
Changes in noncurrent assets	(6.5)	(26.4)
Changes in noncurrent liabilities	(3.9)	(17.6)
Net cash provided by operating activities	295.4	297.3
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt - net of issuance costs	232.7	99.5
Additional capital contribution	4.5	5.4
Requirements for:		
Dividends to parent	(78.8)	(76.0)
Retirement of long-term debt	(337.5)	—
Net change in short-term borrowings	59.4	(142.7)
Net cash used in financing activities	(119.7)	(113.8)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	0.8	2.3
Requirements for:		
Capital expenditures, excluding AFUDC equity	(183.6)	(186.6)
Other investments	—	(0.2)
Net cash used in investing activities	(182.8)	(184.5)
Net change in cash & cash equivalents	(7.1)	(1.0)
Cash & cash equivalents at beginning of period	13.3	6.0
Cash & cash equivalents at end of period	$6.2	$5.0

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

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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 or Utility Holdings), 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 or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. 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 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 110,000 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 311,000 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, 2012, filed with the Securities and Exchange Commission on March 1, 2013, 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 $176 million is outstanding at September 30, 2013, and Utility Holdings' has unsecured senior notes with a par value of $725 million outstanding at September 30, 2013. 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.

Condensed Consolidating Balance Sheet as of September 30, 2013 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$5.4	$0.8	$—	$6.2
Accounts receivable - less reserves	69.9	—	—	69.9
Intercompany receivables	—	84.4	(84.4)	—
Accrued unbilled revenues	33.1	—	—	33.1
Inventories	98.4	0.1	—	98.5
Recoverable fuel & natural gas costs	19.5	—	—	19.5
Prepayments & other current assets	49.6	30.3	(25.8)	54.1
Total current assets	275.9	115.6	(110.2)	281.3
Utility Plant				
Original cost	5,326.9	—	—	5,326.9
Less: accumulated depreciation & amortization	2,136.3	—	—	2,136.3
Net utility plant	3,190.6	—	—	3,190.6
Investments in consolidated subsidiaries	—	1,364.5	(1,364.5)	—
Notes receivable from consolidated subsidiaries	—	696.4	(696.4)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	28.1	4.5	—	32.6
Nonutility property - net	2.3	141.2	—	143.5
Goodwill - net	205.0	—	—	205.0
Regulatory assets	113.2	22.2	—	135.4
Other assets	33.8	1.1	(7.5)	27.4
TOTAL ASSETS	$3,849.1	$2,345.5	$(2,178.6)	$4,016.0

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$91.5	$4.7	$—	$96.2
Intercompany payables	11.3	—	(11.3)	—
Payables to other Vectren companies	23.1	—	—	23.1
Accrued liabilities	113.7	15.3	(25.8)	103.2
Short-term borrowings	—	176.1	—	176.1
Intercompany short-term borrowings	73.1	—	(73.1)	—
Total current liabilities	312.7	196.1	(110.2)	398.6
Long-Term Debt				
Long-term debt	382.4	724.6	—	1,107.0
Long-term debt due to VUHI	696.4	—	(696.4)	—
Total long-term debt - net	1,078.8	724.6	(696.4)	1,107.0
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	626.9	0.3	—	627.2
Regulatory liabilities	380.3	1.6	—	381.9
Deferred credits & other liabilities	85.9	2.6	(7.5)	81.0
Total deferred credits & other liabilities	1,093.1	4.5	(7.5)	1,090.1
Common Shareholder's Equity				
Common stock (no par value)	799.3	786.1	(799.3)	786.1
Retained earnings	565.2	634.2	(565.2)	634.2
Total common shareholder's equity	1,364.5	1,420.3	(1,364.5)	1,420.3

TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,849.1	$2,345.5	$(2,178.6)	$4,016.0

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Condensed Consolidating Balance Sheet as of December 31, 2012 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$12.5	$0.8	$—	$13.3
Accounts receivable - less reserves	81.8	—	—	81.8
Intercompany receivables	—	145.1	(145.1)	—
Accrued unbilled revenues	93.6	—	—	93.6
Inventories	114.0	—	—	114.0
Recoverable fuel & natural gas costs	25.3	—	—	25.3
Prepayments & other current assets	52.0	5.8	(5.5)	52.3
Total current assets	379.2	151.7	(150.6)	380.3
Utility Plant				
Original cost	5,176.6	0.2	—	5,176.8
Less: accumulated depreciation & amortization	2,057.2	—	—	2,057.2
Net utility plant	3,119.4	0.2	—	3,119.6
Investments in consolidated subsidiaries	—	1,329.2	(1,329.2)	—
Notes receivable from consolidated subsidiaries	—	679.7	(679.7)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	27.8	4.8	—	32.6
Nonutility property - net	2.6	144.3	—	146.9
Goodwill - net	205.0	—	—	205.0
Regulatory assets	104.1	22.4	—	126.5
Other assets	40.4	1.7	(6.4)	35.7
TOTAL ASSETS	$3,878.7	$2,334.0	$(2,165.9)	$4,046.8
LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$114.8	$6.2	$—	$121.0
Accounts payable to affiliated companies	29.7	—	—	29.7
Intercompany payables	10.6	—	(10.6)	—
Payables to other Vectren companies	25.1	—	—	25.1
Accrued liabilities	131.3	13.5	(5.5)	139.3
Short-term borrowings	—	116.7	—	116.7
Intercompany short-term borrowings	134.5	—	(134.5)	—
Current maturities of long-term debt	5.0	100.0	—	105.0
Total current liabilities	451.0	236.4	(150.6)	536.8
Long-Term Debt				
Long-term debt - net of current maturities	382.3	721.1	—	1,103.4
Long-term debt due to VUHI	679.7	—	(679.7)	—
Total long-term debt - net	1,062.0	721.1	(679.7)	1,103.4
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	595.4	(16.9)	—	578.5
Regulatory liabilities	362.2	2.0	—	364.2
Deferred credits & other liabilities	78.9	1.4	(6.4)	73.9
Total deferred credits & other liabilities	1,036.5	(13.5)	(6.4)	1,016.6
Common Shareholder's Equity				
Common stock (no par value)	787.8	781.6	(787.8)	781.6

Retained earnings	541.4	608.4	(541.4)	608.4
Total common shareholder's equity	1,329.2	1,390.0	(1,329.2)	1,390.0
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,878.7	$2,334.0	$(2,165.9)	$4,046.8

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Condensed Consolidating Statement of Income for the three months ended September 30, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$101.9	$—	$—	$101.9
Electric utility	165.8	—	—	165.8
Other	—	9.4	(9.4)	—
Total operating revenues	267.7	9.4	(9.4)	267.7
OPERATING EXPENSES				
Cost of gas sold	27.5	—	—	27.5
Cost of fuel & purchased power	50.4	—	—	50.4
Other operating	83.1	—	(9.1)	74.0
Depreciation & amortization	44.1	5.4	0.2	49.7
Taxes other than income taxes	11.2	0.4	—	11.6
Total operating expenses	216.3	5.8	(8.9)	213.2
OPERATING INCOME	51.4	3.6	(0.5)	54.5
Other income - net	1.2	9.8	(9.0)	2.0
Interest expense	14.7	10.4	(9.5)	15.6
INCOME BEFORE INCOME TAXES	37.9	3.0	—	40.9
Income taxes	15.0	0.6	—	15.6
Equity in earnings of consolidated companies, net of tax	—	22.9	(22.9)	—
NET INCOME	$22.9	$25.3	$(22.9)	$25.3

Condensed Consolidating Statement of Income for the three months ended September 30, 2012 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$100.2	$—	$—	$100.2
Electric utility	167.9	—	—	167.9
Other	—	10.2	(10.6)	(0.4)
Total operating revenues	268.1	10.2	(10.6)	267.7
OPERATING EXPENSES				
Cost of gas sold	28.1	—	—	28.1
Cost of fuel & purchased power	52.9	—	—	52.9
Other operating	82.3	—	(10.5)	71.8
Depreciation & amortization	40.8	5.3	0.2	46.3
Taxes other than income taxes	11.1	0.4	—	11.5
Total operating expenses	215.2	5.7	(10.3)	210.6
OPERATING INCOME	52.9	4.5	(0.3)	57.1
Other income - net	1.8	10.4	(9.9)	2.3
Interest expense	16.2	11.8	(10.2)	17.8
INCOME BEFORE INCOME TAXES	38.5	3.1	—	41.6
Income taxes	14.5	0.7	—	15.2
Equity in earnings of consolidated companies, net of tax	—	24.0	(24.0)	—
NET INCOME	$24.0	$26.4	$(24.0)	$26.4

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Condensed Consolidating Statement of Income for the nine months ended September 30, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	555.8	—	—	555.8
Electric utility	470.0	—	—	470.0
Other	—	28.4	(28.2)	0.2
Total operating revenues	1,025.8	28.4	(28.2)	1,026.0
OPERATING EXPENSES				
Cost of gas sold	235.4	—	—	235.4
Cost of fuel & purchased power	154.5	—	—	154.5
Other operating	264.3	—	(27.4)	236.9
Depreciation & amortization	130.5	15.9	0.4	146.8
Taxes other than income taxes	40.1	1.2	—	41.3
Total operating expenses	824.8	17.1	(27.0)	814.9
OPERATING INCOME	201.0	11.3	(1.2)	211.1
Other income - net	4.9	28.6	(26.7)	6.8
Interest expense	44.7	32.4	(27.9)	49.2
INCOME BEFORE INCOME TAXES	161.2	7.5	—	168.7
Income taxes	63.8	0.3	—	64.1
Equity in earnings of consolidated companies, net of tax	—	97.4	(97.4)	—
NET INCOME	97.4	104.6	(97.4)	104.6

Condensed Consolidating Statement of Income for the nine months ended September 30, 2012 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	508.5	—	—	508.5
Electric utility	456.6	—	—	456.6
Other	—	30.1	(29.6)	0.5
Total operating revenues	965.1	30.1	(29.6)	965.6
OPERATING EXPENSES				
Cost of gas sold	197.0	—	—	197.0
Cost of fuel & purchased power	144.6	—	—	144.6
Other operating	258.2	0.5	(29.2)	229.5
Depreciation & amortization	124.6	17.7	0.4	142.7
Taxes other than income taxes	37.8	1.1	0.1	39.0
Total operating expenses	762.2	19.3	(28.7)	752.8
OPERATING INCOME	202.9	10.8	(0.9)	212.8
Other income - net	4.0	30.9	(29.7)	5.2
Interest expense	49.1	35.0	(30.6)	53.5
INCOME BEFORE INCOME TAXES	157.8	6.7	—	164.5
Income taxes	62.2	(0.2)	—	62.0
Equity in earnings of consolidated companies, net of tax	—	95.6	(95.6)	—
NET INCOME	95.6	102.5	(95.6)	102.5

Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$276.1	$19.3	$—	$295.4
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from				
Long-term debt - net of issuance costs	232.7	124.4	(124.4)	232.7
Additional capital contribution from parent	11.5	4.5	(11.5)	4.5
Requirements for:				
Dividends to parent	(73.5)	(78.8)	73.5	(78.8)
Retirement of long term debt	(223.6)	(221.6)	107.7	(337.5)
Net change in intercompany short-term borrowings	(61.5)	—	61.5	—
Net change in short-term borrowings	—	59.4	—	59.4
Net cash used in financing activities	(114.4)	(112.1)	106.8	(119.7)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from				
Consolidated subsidiary distributions	—	73.5	(73.5)	—
Other investing activities	0.6	0.2	—	0.8
Requirements for:				
Capital expenditures, excluding AFUDC equity	(169.4)	(14.2)	—	(183.6)
Consolidated subsidiary investments	—	(11.5)	11.5	—
Net change in long-term intercompany notes receivable	—	(16.7)	16.7	—
Net change in short-term intercompany notes receivable	—	61.5	(61.5)	—
Net cash used in investing activities	(168.8)	92.8	(106.8)	(182.8)
Net change in cash & cash equivalents	(7.1)	—	—	(7.1)
Cash & cash equivalents at beginning of period	12.5	0.8	—	13.3
Cash & cash equivalents at end of period	$5.4	$0.8	$—	$6.2

Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2012 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$263.6	$33.7	$—	$297.3
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Additional capital contribution to parent	3.5	5.4	(3.5)	5.4
Long-term debt, net of issuance costs	—	99.5	—	99.5
Requirements for dividends to parent	(47.2)	(76.0)	47.2	(76.0)
Net change in intercompany short-term borrowings	(41.7)	—	41.7	—
Net change in short-term borrowings	—	(142.7)	—	(142.7)
Net cash used in financing activities	(85.4)	(113.8)	85.4	(113.8)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	47.2	(47.2)	—
Other investing activities	—	2.3	—	2.3
Requirements for:				
Capital expenditures, excluding AFUDC equity	(179.8)	(6.8)	—	(186.6)
Consolidated subsidiary investments	—	(3.5)	3.5	—

Other investing activities	(0.2)	—	—	(0.2)
Net change in short-term intercompany notes receivable	—	41.7	(41.7)	—
Net cash used in investing activities	(180.0)	80.9	(85.4)	(184.5)
Net change in cash & cash equivalents	(1.8)	0.8	—	(1.0)
Cash & cash equivalents at beginning of period	5.3	0.7	—	6.0
Cash & cash equivalents at end of period	$3.5	$1.5	$—	$5.0

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 as a component of operating revenues, which totaled $4.8 million in both the three months ended September 30, 2013 and 2012. For the nine months ended September 30, 2013 and 2012, these taxes totaled $20.9 million and $19.1 million, respectively. 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 September 30, 2013 and December 31, 2012, the Company has accruals related to utility and nonutility plant purchases totaling approximately $9.5 million and $7.1 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Fuels, Inc. (Vectren Fuels)
Vectren Fuels, a wholly owned subsidiary of Vectren, owns coal mines from which SIGECO purchases coal used for electric generation. The price of coal that is charged by Vectren Fuels to SIGECO is priced consistent with contracts reviewed by the OUCC and on file with the IURC. Amounts purchased for the three months ended September 30, 2013 and 2012 totaled $24.5 million and $24.3 million, respectively, and for the nine months ended September 30, 2013 and 2012 totaled $76.1 million and $82.5 million, respectively. Amounts owed to Vectren Fuels at September 30, 2013 and December 31, 2012 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of Vectren, performs natural gas and water distribution, transmission, and construction repair and rehabilitation primarily in the Midwest and the repair and rehabilitation of gas, water, and wastewater facilities nationwide. In addition, VISCO also provides transmission pipeline construction and maintenance; pump station, compressor station, terminal and refinery construction; and hydrostatic testing to customers generally in the northern Midwest region. VISCO's customer's include Utility Holdings' utilities. Fees incurred by Utility Holdings and its subsidiaries totaled $15.9 million and $17.0 million for the three months ended September 30, 2013 and 2012, respectively, and for the nine months ended September 30, 2013 and 2012 totaled $39.5 million and $37.7 million, respectively. Amounts owed to VISCO at September 30, 2013 and December 31, 2012 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

ProLiance Holdings, LLC (ProLiance)
Vectren has an investment in ProLiance, a nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy). ProLiance Energy provided services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance Energy's customers included, among others, Vectren's Indiana utilities as well as Citizens' utilities.

Purchases from ProLiance for resale and for injections into storage for the three months ended September 30, 2012 totaled $57.2 million, and for the nine months ended September 30, 2013 and 2012 totaled $200.5 million and $186.9 million, respectively. The Company had no purchases during the third quarter of 2013 as a result of Proliance exiting the natural gas marketing business. The Company did not have any amounts owed to ProLiance for purchases at September 30, 2013 and amounts owed to ProLiance at December 31, 2012 were $29.7 million and are included in Accounts payable to affiliated companies in the Condensed Consolidated Balance Sheets.

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Support Services & Purchases

Vectren provides corporate and general and administrative services to the Company and allocates costs to the Company. These costs have been 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 September 30, 2013 and 2012, Utility Holdings received corporate allocations totaling $10.4 million and $8.2 million, respectively. For the nine months ended September 30, 2013 and 2012, Utility Holdings received corporate allocations totaling $36.7 million and $32.1 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

SIGECO 2013 Debt Refund and Reissuance

During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95% per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

Utility Holdings Debt Transactions

On April 1, 2013, the Company executed an early redemption at par of $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012 with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8 million and $79.6 million. respectively. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

On August 22, 2013, VUHI entered into a private placement Note Purchase Agreement pursuant to which institutional investors have agreed to purchase $150 million of Senior Guaranteed Notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The Notes will be unconditionally guaranteed by Indiana Gas, SIGECO, and VEDO. The Company expects to receive net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which will be used to refinance $100 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes. Subject to the satisfaction of customary conditions precedent, the notes will be funded on or about December 5, 2013, as a result of the delayed draw feature.

8. Commitments & Contingencies

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.

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9. Rate & Regulatory Matters

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

Ohio Recovery and Deferral Mechanisms
The PUCO order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post in service carrying costs is also allowed until the related capital expenditures are recovered through the DRR. The order also established a prospective bill impact evaluation on the annual deferrals, limiting the deferrals at a level which would equal a change over the prior year rate of $1.00 per residential and general service customer per month. To date, the Company has made capital investments under this rider totaling $101 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $8.7 million and $6.5 million at September 30, 2013 and December 31, 2012, respectively. The DRR's initial five year term expires in early 2014. The Company filed a request in August 2013 to extend the term of the DRR and expand the DRR to include recovery of other infrastructure investments. In that filing, the Company detailed a five-year capital expenditure plan for calendar years 2013 through 2017 totaling $187 million related to the applicable infrastructure investments. As is typical, other parties have intervened in the case and discovery is ongoing. The Company expects an order in early 2014.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. The legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law, reflecting its $23.5 million capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. On August 29, 2013, the Company filed a request for the accounting authority described above on its capital expenditure program for the 2013 calendar year totaling $61.5 million. Of this amount, $34.8 million relates to expenditures that could be considered recoverable under the DRR discussed above. If not ultimately included in the DRR, the Company would anticipate deferral for future recovery through a House Bill 95 mechanism. In addition, the Company requested that subsequent requests for accounting authority will be filed annually in April. The Company expects an order before the end of 2013.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received orders in 2008 and 2007 associated with the most recent base rate cases. These orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Vectren North and $3 million annually at Vectren South. The debt-related post in

service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. Such deferral is limited by individual qualifying project to three years after being placed into service at Vectren South and four years after being placed into service at Vectren North.

In April 2011, Senate Bill 251 was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on

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the federally mandated capital investment, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs are to be deferred for future recovery in the utility's next general rate case.

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally-mandated investment, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Pipeline Safety Law

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

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. It is expected that the law will result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure and, therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses.

Requests for Recovery Under Regulatory Mechanisms

The Company plans to utilize the mechanisms described above to recover certain costs of federally mandated projects and other capital investment projects outside of base rate proceedings. As discussed in detail above, the Company filed in Ohio in August 2013 a request seeking authority to extend the term of the DRR and expand the DRR to include for recovery of other infrastructure investments. The Company also expects to seek authority to recover appropriate costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with the Pipeline Safety Law, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. Such requests are expected to be made in the near term. The Company has communicated its intent to make such filings with all appropriate parties. When filed, it is expected that the combined Indiana infrastructure replacement and improvement plan required by the legislation will reflect estimated construction costs of $800 to $900 million over the seven year period beginning in 2014 and $5 to $10 million in annual operating costs associated with compliance with new pipeline safety regulations. These recovery mechanisms are not yet in place in Indiana but are authorized under the newly enacted legislation described previously. While the regulatory framework is therefore not yet fully developed, it is expected that these costs will be recoverable under the mechanisms provided for in Senate Bills 251 and 560.

Vectren North Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. A settlement in the case has now been reached with the Pipeline Safety Division of the IURC and a hearing on the settlement will be conducted in November 2013.

10. Environmental Matters

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

Air Quality

Clean Air Interstate Rule / Cross-State Air Pollution Rule

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

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR’s implementation by Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA agreed to reconsider MATS requirements for new construction. Such requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013.

Notice of Violation for A.B. Brown Power Plant

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed.

Information Request

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

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

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

Conclusions Regarding Environmental Regulations
To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal-fired generating fleet is 100 percent scrubbed for 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.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Due to the correlation among the various requirements set forth, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts. Currently, it is expected that the capital costs could be between $80 million and $110 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. The Company is evaluating current and/or deferral of regulatory recovery that will moderate the impact on customer rates in the near term.

Coal Ash Waste Disposal & Ash Ponds

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

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

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

The EPA has promulgated two GHG regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards (NSPS) for GHG's for new electric generating facilities under the Clean Air Act Section 111(b). On October 15, the US Supreme Court agreed to review a focused appeal on the issue of whether the GHG rule applicable to mobile sources triggered PSD permitting for all stationary sources such as Vectren's power plants. A decision is not expected until 2014.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to re-propose and finalize the new source rule expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. The President's Climate Action Plan did not provide any detail as to actual emission targets or compliance requirements. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

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

Impact of Legislative Actions & Other Initiatives is Unknown
If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as

technology becomes available to control GHG emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity

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obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment.

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

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

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

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.2 million of the expected $15.7 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 September 30, 2013 and December 31, 2012, approximately $5.1 million and $4.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

11. Fair Value Measurements

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

	September 30, 2013		December 31, 2012	
(In millions)	Carrying	Est. Fair	Carrying	Est. Fair

	Amount	Value	Amount	Value
Long-term debt	$1,107.0	$1,210.4	$1,208.4	$1,372.6
Short-term borrowings	176.1	176.1	116.7	116.7
Cash & cash equivalents	6.2	6.2	13.3	13.3

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

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

Under current regulatory treatment, call premiums on reacquisition of 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.

12. Impact of Recently Issued Accounting Principles and Other Authoritative Guidance

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

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

Unrecognized Tax Benefit Presentation
In July 2013, the FASB issued new accounting guidance on presenting an unrecognized tax benefit when net operating loss carryforwards exist. The new standard was issued in an effort to eliminate diversity in practice resulting from a lack of guidance on this topic in the current US GAAP. The update provides that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except under certain circumstances outlined in the update. The amendments in the update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, with early adoption permitted. This update is consistent with how the Company currently presents unrecognized tax benefits, therefore, adoption of this guidance resulted in no material impact on the Company's financial statements.

Final Federal Income Tax Regulations

In September 2013, the Internal Revenue Service (IRS) released final tangible property regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, but may be adopted for 2013 tax years. The Company intends to adopt the guidance for its 2014 tax year. The Company continues to evaluate the impact adoption of the regulations will have on its consolidated financial statements. As of this date, the Company does not expect the adoption of the regulations to have a material impact on its consolidated financial statements.

13. 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 Gas Utility Services and Electric Utility Services. Gas Utility Services provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio. Electric Utility Services provides electric distribution services to southwestern Indiana, and includes the Company's power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Company is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company's business segments is summarized below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Revenues				
Gas Utility Services	$101.9	$100.2	$555.8	$508.5
Electric Utility Services	165.8	167.9	470.0	456.6
Other Operations	9.5	10.2	28.5	30.1
Eliminations	(9.5)	(10.6)	(28.3)	(29.6)
Total revenues	$267.7	$267.7	$1,026.0	$965.6
Profitability Measure - Net Income (Loss)				
Gas Utility Services	$(3.8)	$(2.7)	$37.2	$36.1
Electric Utility Services	26.6	26.6	60.1	59.4
Other Operations	2.5	2.5	7.3	7.0
Total net income	$25.3	$26.4	$104.6	$102.5

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

Description of the Business

Vectren Utility Holdings, Inc. (the Company or Utility Holdings), 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 or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also earns a return on shared assets that provide information technology and other services to the three utilities. 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 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 110,000 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 311,000 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.

Executive Summary of Consolidated Results of Operations

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company’s 2012 annual report filed on Form 10-K.

In the third quarter of 2013, Utility Holding's earnings were $25.3 million compared to $26.4 million in 2012. For the nine months ended September 30, 2013, Utility Holdings' earnings were $104.6 million, compared to $102.5 million in 2012. The improved year to date 2013 results are primarily related to increased gas utility margins from small and large customers, return on electric transmission investment, and lower interest expense.

Gas Utility Services

During the third quarter of 2013, Gas Utility Services reported a seasonal loss of $3.8 million compared to a loss of $2.7 million in the third quarter of 2012. The third quarter 2013 results were lower primarily due to increased depreciation expense associated with plant placed into service during the year. For the nine months ended September 30, 2013, Gas Utility Services' earnings were $37.2 million, compared to earnings of $36.1 million in 2012. Results in 2013 have been favorably impacted by small customer growth and increased large customer margin, offset by higher depreciation expense and operating costs. Results also continue to be favorably impacted by returns earned on increased investment in bare steel and cast iron pipe replacements, particularly in Ohio, and by lower interest expense.

Electric Utility Services

During the third quarter of 2013, Electric Utility Services' earnings were $26.6 million, flat to the same period in 2012. Electric Utility Services earned $60.1 million year to date in 2013, compared to earnings of $59.4 million for the nine months ended September 30, 2012. In both the third quarter and year to date periods, results were favorably impacted by lower interest expense offset by lower electric small customer margin resulting from conservation initiatives, net of lost margin recovery, and cooling weather that was significantly warmer in 2012 as compared to 2013. The 2012 results reflect refunds to customers pursuant to refunds arising from statutory net operating income limits. No such refunds have occurred or are expected in 2013.

Other Utility Operations

In the third quarter of 2013, earnings from Other Utility operations were $2.5 million, about flat compared to 2012. In the nine months ended September 30, 2013, earnings from these operations were $7.3 million compared to $7.0 million in 2012.

Operating Trends
Margin

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Gas utility revenues	$101.9	$100.2	$555.8	$508.5
Cost of gas sold	27.5	28.1	235.4	197.0
Total gas utility margin	$74.4	$72.1	$320.4	$311.5
Margin attributed to:				
Residential & commercial customers	$56.4	$55.3	$243.4	$238.0
Industrial customers	12.1	11.9	41.9	39.8
Other	2.2	1.4	7.6	6.8
Regulatory expense recovery mechanisms	3.7	3.5	27.5	26.9
Total gas utility margin	$74.4	$72.1	$320.4	$311.5
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	6.5	6.3	73.6	57.3
Industrial customers	24.6	25.1	80.7	77.2
Total sold & transported volumes	31.1	31.4	154.3	134.5

Gas Utility margins were $74.4 million and $320.4 million for the three and nine months ended September 30, 2013, and compared to 2012 increased $2.3 million in the quarter and $8.9 million year to date. Excluding the impact of regulatory expense recovery mechanisms, small customer margins increased $1.1 million quarter over quarter and $5.4 million year to date, compared to the prior year. Growth in residential and commercial customers favorably impacted small customer margins by approximately $0.4 million for the quarter and $2.3 million for the year to date. In addition, recovery related to investments in infrastructure in Ohio increased margin $0.7 million and $2.4 million in the quarter and year to date periods, respectively, compared to the prior year. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 103 percent of normal in Ohio and equal to normal in Indiana during the nine months ended September 30, 2013, compared to 83 percent of normal in Ohio and 71 percent of normal in Indiana during 2012, only had a slight favorable impact to small customer margin. Large customer margins increased $0.2 million and $2.1 million in the quarter and year to date periods, respectively, compared to the prior year, on increasing volumes.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Electric utility revenues	$165.8	$167.9	$470.0	$456.6
Cost of fuel & purchased power	50.4	52.9	154.5	144.6
Total electric utility margin	$115.4	$115.0	$315.5	$312.0
Margin attributed to:				
Residential & commercial customers	$73.8	$77.0	$195.0	$200.1
Industrial customers	28.6	29.3	82.5	83.9
Other customers	1.4	(0.9)	3.1	(0.4)
Regulatory expense recovery mechanisms	2.2	0.9	6.7	2.9
Subtotal: retail	$106.0	$106.3	$287.3	$286.5
Wholesale power & transmission system margin	9.4	8.7	28.2	25.5
Total electric utility margin	$115.4	$115.0	$315.5	$312.0
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	769.6	813.8	2,072.1	2,138.2
Industrial customers	729.7	732.5	2,087.0	2,127.6
Other customers	4.9	5.3	15.5	16.0
Total retail volumes sold	1,504.2	1,551.6	4,174.6	4,281.8

Retail

Electric retail utility margins were $106.0 million and $287.3 million for the three and nine months ended September 30, 2013, and compared to 2012 decreased by $0.3 million in the quarter and increased $0.8 million year to date. Excluding the impact of regulatory expense recovery mechanisms, small customer margins decreased by $3.2 million for the quarter and $5.1 million year to date compared to 2012. Electric results are not protected by weather normalizing mechanisms. Cooling degree days in 2013 were 101 percent of normal compared to 131 percent of normal in 2012, resulting in lower small customer margin of $4.5 million in the quarter and $3.3 million year to date, compared to the prior year. in addition, small customer margin declined $0.4 million for the quarter and $3.5 million for the year to date period as a result of customer energy conservation, net of approved lost margin recovery mechanisms. These declines in small customer margin were somewhat offset by an unfavorable adjustment in the prior year of $1.6 million. Large customer margins for the third quarter of 2013 declined $0.7 million from the prior year, and for the nine months decreased $1.4 million from 2012 on lower volumes. Other margin was higher in both the quarter and year to date periods due to refunds during 2012 resulting from statutory net operating income limits. Margin from regulatory expense recovery mechanisms increased $1.3 million for the third quarter and $3.8 million for the nine months compared to 2012, driven by increased operating expenses associated with the electric state-mandated conservation programs. This is offset by a corresponding increase in operating expenses when compared to 2012.

Margin from Wholesale Electric Activities

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

	Three Months Ended September 30,		Nine Months Ended September 30,	

(In millions)	2013	2012	2013	2012
Transmission system sales	$8.6	$7.7	$23.1	$20.8
Off-system sales	0.8	1.0	5.1	4.7
Total wholesale margin	$9.4	$8.7	$28.2	$25.5

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $23.1 million and $20.8 million during the nine months ended September 30, 2013 and 2012, respectively. During the 2013 third quarter, transmission system margin was $8.6 million compared to $7.7 million for the same period in 2012. Increases are primarily due to increased investment in qualifying projects. As of September 30, 2013, the Company had invested approximately $159 million in qualifying projects. These projects include an interstate 345 Kv transmission line that connects Vectren's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. Once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance, and operating expenses are also recovered. The 345 Kv project is the largest of these qualifying projects, with a cost of $107 million that earned the FERC approved equity rate of return, including while under construction. The last segment of that project was placed into service in December 2012.

For the nine months ended September 30, 2013, margin from off-system sales was $5.1 million, compared to $4.7 million for the nine months ended September 30, 2012. In the third quarter of 2013, margin from off system sales was $0.8 million compared to $1.0 million in 2012. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year be shared equally with customers. Results for the periods presented reflect the impact of that sharing.

Operating Expenses

Other Operating

During the third quarter of 2013, other operating expenses increased $2.2 million, partially related to the timing of power supply operating costs. For the nine months ended September 30, 2013, other operating expenses were $236.9 million, an increase of $7.4 million, compared to 2012. Excluding pass through costs, other operating expenses increased $5.2 million year to date, compared to the same period in 2012, primarily associated with increased expense related to company stock price driven performance based compensation. Though higher year to date, operating costs are being managed to be generally flat to the 2012 targeted levels on an annual basis, over time.

Depreciation & Amortization

In the third quarter of 2013, depreciation and amortization expense was $49.7 million, compared to $46.3 million in 2012. For the nine months ended September 30, 2013, depreciation and amortization expense was $146.8 million, which represents an increase of $4.1 million compared to 2012. Both the year to date and quarter periods reflect increased plant placed into service.

Taxes Other Than Income Taxes

Taxes other than income taxes were essentially flat during the three months ended September 30, 2013, compared to 2012. Year to date, taxes other than income taxes were $41.3 million compared to $39.0 million for the year to date period in 2012. The year to date increase of $2.3 million is primarily due to higher revenue taxes associated with increased consumption and higher gas costs. These expenses are offset dollar-for-dollar with lower gas utility and electric utility revenues.

Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

Vectren monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. Vectren's natural gas utilities are currently engaged in replacement programs in both Indiana and

Ohio, the primary purpose of which is preventive maintenance and continual renewal and operational improvement. Laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects and other infrastructure improvement projects, outside of a base rate proceeding. Utilization of these recovery mechanisms is discussed below.

Ohio Recovery and Deferral Mechanisms

The PUCO order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post in service carrying costs is also allowed until the related capital expenditures are recovered through the DRR. The order also established a prospective bill impact evaluation on the annual deferrals, limiting the deferrals at a level which would equal a change over the prior year rate of $1.00 per residential and general service customer per month. To date, the Company has made capital investments under this rider totaling $101 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $8.7 million and $6.5 million at September 30, 2013 and December 31, 2012, respectively. The DRR's initial five year term expires in early 2014. The Company filed a request in August 2013 to extend the term of the DRR and expand the DRR to include recovery of other infrastructure investments. In that filing, the Company detailed a five-year capital expenditure plan for calendar years 2013 through 2017 totaling $187 million related to the applicable infrastructure investments. As is typical, other parties have intervened in the case and discovery is ongoing. The Company expects an order in early 2014.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. The legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law, reflecting its $23.5 million capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. On August 29, 2013, the Company filed a request for the accounting authority described above on its capital expenditure program for the 2013 calendar year totaling $61.5 million. Of this amount, $34.8 million relates to expenditures that could be considered recoverable under the DRR discussed above. If not ultimately included in the DRR, the Company would anticipate deferral for future recovery through a House Bill 95 mechanism. In addition, the Company requested that subsequent requests for accounting authority will be filed annually in April. The Company expects an order before the end of 2013.

Indiana Recovery and Deferral Mechanisms

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

In April 2011, Senate Bill 251 was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs are to be deferred for future recovery in the utility's next general rate case.

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally-mandated investment, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Pipeline Safety Law

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

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. It is expected that the law will result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure and, therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses.

Requests for Recovery Under Regulatory Mechanisms

The Company plans to utilize the mechanisms described above to recover certain costs of federally mandated projects and other capital investment projects outside of base rate proceedings. As discussed in detail above, the Company filed in Ohio in August 2013 a request seeking authority to extend the term of the DRR and expand the DRR to include for recovery of other infrastructure investments. The Company also expects to seek authority to recover appropriate costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with the Pipeline Safety Law, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. Such requests are expected to be made in the near term. The Company has communicated its intent to make such filings with all appropriate parties. When filed, it is expected that the combined Indiana infrastructure replacement and improvement plan required by the legislation will reflect estimated construction costs of $800 to $900 million over the seven year period beginning in 2014 and $5 to $10 million in annual operating costs associated with compliance with new pipeline safety regulations. These recovery mechanisms are not yet in place in Indiana but are authorized under the newly enacted legislation described previously. While the regulatory framework is therefore not yet fully developed, it is expected that these costs will be recoverable under the mechanisms provided for in Senate Bills 251 and 560.

Vectren North Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. A settlement in the case has now been reached with the Pipeline Safety Division of the IURC and a hearing on the settlement will be conducted in November 2013.

Environmental Matters

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

Air Quality

Clean Air Interstate Rule / Cross-State Air Pollution Rule

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

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR's implementation by Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA agreed to reconsider MATS requirements for new construction. Such requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013.

Notice of Violation for A.B. Brown Power Plant

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed.

Information Request

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

Water

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

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

Conclusions Regarding Environmental Regulations

To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal-fired generating fleet is 100 percent scrubbed for 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.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Due to the correlation among the various requirements set forth, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts. Currently, it is expected that the capital costs could be between $80 million and $110 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. The Company is evaluating current and/or deferral of regulatory recovery that will moderate the impact on customer rates in the near term.

Coal Ash Waste Disposal & Ash Ponds

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

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

Climate Change

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

The EPA has promulgated two GHG regulations that apply to the Company’s generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards (NSPS) for GHG's for new electric generating facilities under the Clean Air Act Section 111(b). On October 15, the US Supreme Court agreed to review a focused appeal on the issue of whether the GHG rule applicable to mobile sources triggered PSD permitting for all stationary sources such as Vectren's power plants. A decision is not expected until 2014.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to re-propose and finalize the new source rule expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. The President's Climate Action Plan did not provide any detail as to actual emission targets or compliance requirements. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

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

Impact of Legislative Actions & Other Initiatives is Unknown

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

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment.

Manufactured Gas Plants

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

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

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

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.2 million of the expected $15.7 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 September 30, 2013 and December 31, 2012, approximately $5.1 million and $4.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance and Other Authoritative Guidance

Offsetting Assets and Liabilities

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

Accumulated Other Comprehensive Income (AOCI)

In February 2013, the FASB issued new accounting guidance on the reporting of reclassifications from AOCI. The guidance requires an entity to report the effect of significant reclassification from AOCI on the respective line items in net income if the amount being reclassified is required under US GAAP to be reclassified in its entirety to net income. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference to other disclosures required that provide additional details about these amounts. The new guidance is effective for fiscal years, and interim periods within annual periods, beginning after December 15, 2012. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the company's results of operations, cash flows or financial position.

Unrecognized Tax Benefit Presentation
In July 2013, the FASB issued new accounting guidance on presenting an unrecognized tax benefit when net operating loss carryforwards exist. The new standard was issued in an effort to eliminate diversity in practice resulting from a lack of guidance on this topic in the current US GAAP. The update provides that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except under certain circumstances outlined in the update. The amendments in the update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, with early adoption permitted. This update is consistent with how the Company currently presents unrecognized tax benefits, therefore, adoption of this guidance resulted in no material impact on the Company's financial statements.

Final Federal Income Tax Regulations
In September 2013, the Internal Revenue Service (IRS) released final tangible property regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, but may be adopted for 2013 tax years. The Company intends to adopt the guidance for its 2014 tax year. The Company continues to evaluate the impact adoption of the regulations will have on its consolidated financial statements. As of this date, the Company does not expect the adoption of the regulations to have a material impact on its consolidated financial statements.

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, and short-term obligations outstanding at September 30, 2013 approximated $725 million and $176 million, respectively. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at September 30, 2013, approximated $382 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 September 30, 2013, are A-/A3 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. The credit ratings on SIGECO's secured debt are A/A1. Utility Holdings' commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody's and Standard and Poor's is stable. In November 2013, Moody's placed the ratings of most regulated utilities and utility holding companies, including VUHI, SIGECO, and Indiana Gas on review for upgrade. These companies have been placed on review because Moody's has adopted a generally more favorable view of the relative credit supportiveness of the US regulatory environment. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-60 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 56 percent of long-term capitalization at September 30, 2013 and 53 percent at December 31, 2012. Long-term capitalization includes long-term debt, including current maturities and debt subject to tender, 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 September 30, 2013, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

The Company's A-/A3 investment grade credit ratings have allowed it to access the capital markets as needed, and the Company believes it will have the ability to continue to do so. Given the Company's intent to maintain a balanced long-term capitalization ratio, it generally anticipates funding future capital expenditures and dividends principally through internally generated funds, which have recently been enhanced by bonus depreciation legislation, and refinancing maturing or callable debt using the capital markets. However, due to the planned increase in capital expenditures for the gas utilities and given the uncertainty around additional capital expenditures due to pending legislative and regulatory initiatives involving gas pipeline infrastructure replacement; and expanded EPA regulations for air, water, and fly ash, incremental financing to fund such capital expenditures may be required in the future. The timing and amount of such investments depends on a variety of factors, including available liquidity.

Specifically for 2013, the Company has accessed the capital markets to refinance debt maturities or debt that is callable. During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95 percent per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

On April 1, 2013, the Company executed an early redemption at par of $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012 with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8 million and $79.6 million. respectively. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

On August 22, 2013, VUHI entered into a private placement note purchase agreement pursuant to which institutional investors have agreed to purchase $150 million of senior guaranteed notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The notes will be unconditionally guaranteed by Indiana Gas, SIGECO, and VEDO. The Company expects to receive net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which will be used to refinance $100.0 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes. Subject to the satisfaction of customary conditions precedent, the notes will be funded on or about December 5, 2013, as a result of the delayed draw feature.

Consolidated Short-Term Borrowing Arrangements

At September 30, 2013, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $174 million was available at September 30, 2013. This short-term borrowing facility is available through September 2016. 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 the short-term borrowing needs of Utility Holdings' operations through the commercial paper market and expects to use the Utility Holdings short-term borrowing facility in instances where the commercial paper market is not efficient. Following is certain information regarding these short-term borrowing arrangements.

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

(In millions)	2013	2012
As of September 30		
Balance Outstanding	$176.1	$100.1
Weighted Average Interest Rate	0.31%	0.46%
Nine Months Ended September 30 Average		
Balance Outstanding	$121.4	$69.5
Weighted Average Interest Rate	0.35%	0.48%
Maximum Month End Balance Outstanding	$176.1	$100.1
Quarterly Average - September 30		
Balance Outstanding	$153.8	$63.8
Weighted Average Interest Rate	0.34%	0.47%
Maximum Month End Balance Outstanding	$176.1	$100.1

Potential Uses of Liquidity

Planned Capital Expenditures
Utility capital expenditures are estimated at $100 million for the remainder of 2013.

Pension Funding Obligations
Vectren's management currently estimates contributing approximately $10 million to qualified pension plans in 2013. A portion of this funding will be from Utility Holdings and occurs through a routine cash settlement process with its parent.

Other Letters of Credit
As of September 30, 2013, Utility Holdings has letters of credit outstanding in support of two SIGECO tax exempt adjustable rate first mortgage bonds totaling $41.7 million. In the unlikely event the letters of credit were called, the Company could settle with the financial institutions supporting these letters of credit with general assets or by drawing from its credit facility that expires in September 2016. Due to the long-term nature of the credit agreement, such debt is classified as long-term at September 30, 2013.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow
The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $295.4 million and $297.3 million during the nine months ended September 30, 2013 and 2012, respectively. While overall cash flow from operations was relatively flat year over year, cash generated from working capital decreased in 2013 and was partially offset by the prior year change in non-current assets driven by the deferral for future recovery of certain coal costs pursuant to a regulatory order in the prior year.

Financing Cash Flow
Net cash flow required for financing activities was $119.7 million and $113.8 million during the nine months ended September 30, 2013 and 2012, respectively. The cash requirements in both periods reflect the payment of dividends and debt refinancing activity.

Investing Cash Flow

Cash flow required for investing activities was $182.8 million and $184.5 million during the nine months ended September 30, 2013 and 2012, respectively. The primary use of cash in both periods presented reflect expenditures for utility plant.

Forward-Looking Information

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

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to fossil fuel costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks or other similar occurrences could adversely affect Vectren's facilities, operations, financial condition and results of operations.
- Increased competition in the energy industry, including the effects of industry restructuring, 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 traditional regulation, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas and electricity; 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.
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, interest rate, and warranty risks.
- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
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- Risks associated with material business transactions such as mergers, acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with state and federal laws and interpretations of these laws.

- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.
- The performance of projects undertaken by Vectren’s nonutility businesses and the success of efforts to realize value from, invest in and develop new opportunities, including but not limited to, Vectren’s infrastructure services, energy services, coal mining, and remaining energy marketing businesses and/or assets.

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 & 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 may also execute derivative contracts in the normal course of operations while buying and selling commodities to be used in operations and optimizing its generation assets.

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. 2012 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS & PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended September 30, 2013, there have been no changes to the Company’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of September 30, 2013, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of September 30, 2013, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II. 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,

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

ITEM 1A. RISK FACTORS

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

12 Ratio of Earnings to Fixed Charges

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

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

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

101 Interactive Data File.

101.INS XBRL Instance Document

101.SCH XBRL Taxonomy Extension Schema

101.CAL XBRL Taxonomy Extension Calculation Linkbase

101.DEF XBRL Taxonomy Extension Definition Linkbase

101.LAB XBRL Taxonomy Extension Labels Linkbase

101.PRE XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

Pursuant to the requirements of 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

November 14, 2013

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

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