VECTREN UTILITY HOLDINGS INC
Form 10-Q
November 09, 2012

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, 2012
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, 2012
Class	Number of Shares	Date

Access to Information

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

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

Definitions

AFUDC: allowance for funds used during construction

EPA: United States Environmental Protection Agency

FAC: Fuel Adjustment Clause

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

IDEM: Indiana Department of Environmental Management

IURC: Indiana Utility Regulatory Commission

MCF / BCF: thousands / billions of cubic feet

MDth / MMDth: thousands / millions of dekatherms

MISO: Midwest Independent System Operator

MMBTU: millions of British thermal units

MW: megawatts

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

OCC: Ohio Office of the Consumer Counselor

OUCC: Indiana Office of the Utility Consumer Counselor

PUCO: Public Utilities Commission of Ohio

Throughput: combined gas sales and gas transportation volumes

XBRL: eXtensible Business Reporting Language

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash & cash equivalents	$5.0	$6.0
Accounts receivable - less reserves of $5.0 & $5.9, respectively	54.2	95.5
Receivables due from other Vectren companies	—	0.2
Accrued unbilled revenues	29.3	90.8
Inventories	118.4	132.5
Recoverable fuel & natural gas costs	21.4	12.4
Prepayments & other current assets	51.6	69.3
Total current assets	279.9	406.7
Utility Plant		
Original cost	5,141.6	4,979.9
Less: accumulated depreciation & amortization	2,030.5	1,947.3
Net utility plant	3,111.1	3,032.6
Investments in unconsolidated affiliates	0.2	0.2
Other investments	32.7	31.8
Nonutility plant - net	142.8	156.6
Goodwill - net	205.0	205.0
Regulatory assets	125.7	100.0
Other assets	36.9	41.6
TOTAL ASSETS	$3,934.3	$3,974.5

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

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

	September 30, 2012	December 31, 2011
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$94.0	$112.9
Accounts payable to affiliated companies	15.4	36.8
Payables to other Vectren companies	20.7	30.1
Refundable fuel & natural gas costs	1.1	—
Accrued liabilities	103.9	121.0
Short-term borrowings	100.1	142.8
Current maturities of long-term debt	105.0	—
Total current liabilities	440.2	443.6
Long-Term Debt - Net of Current Maturities	1,103.4	1,208.2
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	572.0	537.5
Regulatory liabilities	359.1	345.2
Deferred credits & other liabilities	81.1	93.4
Total deferred credits & other liabilities	1,012.2	976.1
Commitments & Contingencies (Notes 8 - 11)		
Common Shareholder's Equity		
Common stock (no par value)	780.0	774.6
Retained earnings	598.5	572.0
Accumulated other comprehensive income	—	—
Total common shareholder's equity	1,378.5	1,346.6
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,934.3	$3,974.5

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,	
	2012	2011	2012	2011
OPERATING REVENUES				
Gas utility	$100.2	$102.1	$508.5	$592.8
Electric utility	167.9	186.7	456.6	492.4
Other	(0.4)	0.5	0.5	1.5
Total operating revenues	267.7	289.3	965.6	1,086.7
OPERATING EXPENSES				
Cost of gas sold	28.1	30.5	197.0	274.4
Cost of fuel & purchased power	52.9	67.1	144.6	186.9
Other operating	71.8	66.7	229.5	231.8
Depreciation & amortization	46.3	47.8	142.7	143.9
Taxes other than income taxes	11.5	11.6	39.0	40.7
Total operating expenses	210.6	223.7	752.8	877.7
OPERATING INCOME	57.1	65.6	212.8	209.0
Other income - net	2.3	0.1	5.2	4.0
Interest expense	17.8	20.4	53.5	61.2
INCOME BEFORE INCOME TAXES	41.6	45.3	164.5	151.8
Income taxes	15.2	17.4	62.0	59.0
NET INCOME	$26.4	$27.9	$102.5	$92.8

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

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

	Nine Months Ended September 30,	
	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$102.5	$92.8
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	142.7	143.9
Deferred income taxes & investment tax credits	38.1	49.8
Expense portion of pension & postretirement periodic benefit cost	3.4	3.4
Provision for uncollectible accounts	5.9	9.0
Other non-cash expense - net	4.8	7.9
Changes in working capital accounts:		
Accounts receivable, including to Vectren companies & accrued unbilled revenue	97.1	128.2
Inventories	14.1	(9.2)
Recoverable/refundable fuel & natural gas costs	(7.9)	(8.1)
Prepayments & other current assets	10.3	14.4
Accounts payable, including to Vectren companies & affiliated companies	(52.4)	(111.7)
Accrued liabilities	(17.3)	(13.8)
Changes in noncurrent assets	(26.4)	(49.7)
Changes in noncurrent liabilities	(17.6)	(4.3)
Net cash flows from operating activities	297.3	252.6
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt - net of issuance costs	99.5	—
Additional capital contribution	5.4	—
Requirements for:		
Dividends to parent	(76.0)	(68.7)
Retirement of long-term debt	—	(0.7)
Other financing activities	—	—
Net change in short-term borrowings, including from other Vectren companies	(142.7)	(8.7)
Net cash flows used in financing activities	(113.8)	(78.1)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	2.3	0.4
Requirements for:		
Capital expenditures, excluding AFUDC equity	(186.6)	(170.5)
Other investments	(0.2)	(0.8)
Net cash flows used in investing activities	(184.5)	(170.9)
Net change in cash & cash equivalents	(1.0)	3.6
Cash & cash equivalents at beginning of period	6.0	2.4
Cash & cash equivalents at end of period	$5.0	$6.0

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 564,000 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 310,000 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, 2011, filed with the Securities and Exchange Commission on March 2, 2012, 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 $100 million is outstanding at September 30, 2012, and Utility Holdings' has unsecured senior notes with a par value of $821 million outstanding at September 30, 2012. The guarantees are full and unconditional and joint and several, and Utility Holdings has no 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, 2012 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$3.5	$1.5	$—	$5.0
Accounts receivable - less reserves	54.2	—	—	54.2
Intercompany receivables	—	127.6	(127.6)	—
Accrued unbilled revenues	29.3	—	—	29.3
Inventories	118.6	(0.2)	—	118.4
Recoverable fuel & natural gas costs	21.4	—	—	21.4
Prepayments & other current assets	53.9	19.4	(21.7)	51.6
Total current assets	280.9	148.3	(149.3)	279.9
Utility Plant				
Original cost	5,141.6	—	—	5,141.6
Less: accumulated depreciation & amortization	2,030.5	—	—	2,030.5
Net utility plant	3,111.1	—	—	3,111.1
Investments in consolidated subsidiaries	—	1,324.0	(1,324.0)	—
Notes receivable from consolidated subsidiaries	—	679.7	(679.7)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	27.9	4.8	—	32.7
Nonutility property - net	2.7	140.1	—	142.8
Goodwill - net	205.0	—	—	205.0
Regulatory assets	103.1	22.6	—	125.7
Other assets	41.2	2.3	(6.6)	36.9
TOTAL ASSETS	$3,772.1	$2,321.8	$(2,159.6)	$3,934.3

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$89.0	$5.0	$—	$94.0
Accounts payable to affiliated companies	15.4	—	—	15.4
Intercompany payables	10.8	—	(10.8)	—
Payables to other Vectren companies	20.7	—	—	20.7
Refundable fuel & natural gas costs	1.1	—	—	1.1
Accrued liabilities	102.1	23.5	(21.7)	103.9
Short-term borrowings	—	100.1	—	100.1
Intercompany short-term borrowings	116.8	—	(116.8)	—
Current maturities of long-term debt	5.0	100.0	—	105.0
Total current liabilities	360.9	228.6	(149.3)	440.2
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	581.9	(9.9)	—	572.0
Regulatory liabilities	357.0	2.1	—	359.1
Deferred credits & other liabilities	86.3	1.4	(6.6)	81.1
Total deferred credits & other liabilities	1,025.2	(6.4)	(6.6)	1,012.2
Common Shareholder's Equity				

Common stock (no par value)	791.3	780.0	(791.3)	780.0
Retained earnings	532.7	598.5	(532.7)	598.5
Total common shareholder's equity	1,324.0	1,378.5	(1,324.0)	1,378.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,772.1	$2,321.8	$(2,159.6)	$3,934.3

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Condensed Consolidating Balance Sheet as of December 31, 2011 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$5.3	$0.7	$—	$6.0
Accounts receivable - less reserves	94.8	0.7	—	95.5
Intercompany receivables	—	206.0	(206.0)	—
Receivables due from other Vectren companies	—	0.2	—	0.2
Accrued unbilled revenues	90.8	—	—	90.8
Inventories	132.5	—	—	132.5
Recoverable fuel & natural gas costs	12.4	—	—	12.4
Prepayments & other current assets	57.1	16.7	(4.5)	69.3
Total current assets	392.9	224.3	(210.5)	406.7
Utility Plant				
Original cost	4,979.9	—	—	4,979.9
Less: accumulated depreciation & amortization	1,947.3	—	—	1,947.3
Net utility plant	3,032.6	—	—	3,032.6
Investments in consolidated subsidiaries	—	1,272.2	(1,272.2)	—
Notes receivable from consolidated subsidiaries	—	679.7	(679.7)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	26.8	5.0	—	31.8
Nonutility property - net	3.0	153.6	—	156.6
Goodwill - net	205.0	—	—	205.0
Regulatory assets	77.0	23.0	—	100.0
Other assets	44.2	4.0	(6.6)	41.6
TOTAL ASSETS	$3,781.7	$2,361.8	$(2,169.0)	$3,974.5

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$106.1	$6.8	$—	$112.9
Accounts payable to affiliated companies	36.8	—	—	36.8
Intercompany payables	11.8	—	(11.8)	—
Payables to other Vectren companies	30.1	—	—	30.1
Accrued liabilities	112.9	12.6	(4.5)	121.0
Short-term borrowings	—	142.8	—	142.8
Intercompany short-term borrowings	158.5	35.7	(194.2)	—
Total current liabilities	456.2	197.9	(210.5)	443.6
Long-Term Debt				
Long-term debt	387.2	821.0	—	1,208.2
Long-term debt due to VUHI	679.7	—	(679.7)	—
Total long-term debt - net	1,066.9	821.0	(679.7)	1,208.2
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	545.2	(7.7)	—	537.5
Regulatory liabilities	342.6	2.6	—	345.2
Deferred credits & other liabilities	98.6	1.4	(6.6)	93.4
Total deferred credits & other liabilities	986.4	(3.7)	(6.6)	976.1
Common Shareholder's Equity				
Common stock (no par value)	787.8	774.6	(787.8)	774.6

Retained earnings	484.4	572.0	(484.4)	572.0
Total common shareholder's equity	1,272.2	1,346.6	(1,272.2)	1,346.6
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,781.7	$2,361.8	$(2,169.0)	$3,974.5

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 (loss) - 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

Condensed Consolidating Statement of Income for the three months ended September 30, 2011 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$102.1	$—	$—	$102.1
Electric utility	186.7	—	—	186.7
Other	—	11.0	(10.5)	0.5
Total operating revenues	288.8	11.0	(10.5)	289.3
OPERATING EXPENSES				
Cost of gas sold	30.5	—	—	30.5
Cost of fuel & purchased power	67.1	—	—	67.1
Other operating	77.0	—	(10.3)	66.7
Depreciation & amortization	40.9	6.8	0.1	47.8
Taxes other than income taxes	11.2	0.4	—	11.6
Total operating expenses	226.7	7.2	(10.2)	223.7
OPERATING INCOME	62.1	3.8	(0.3)	65.6
Other income (loss) - net	(0.1)	12.6	(12.4)	0.1
Interest expense	18.9	14.2	(12.7)	20.4
INCOME BEFORE INCOME TAXES	43.1	2.2	—	45.3
Income taxes	17.1	0.3	—	17.4
Equity in earnings of consolidated companies, net of tax	—	26.0	(26.0)	—
NET INCOME	$26.0	$27.9	$(26.0)	$27.9

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 (loss) - 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 Income for the nine months ended September 30, 2011 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$592.8	$—	$—	$592.8
Electric utility	492.4	—	—	492.4
Other	—	32.9	(31.4)	1.5
Total operating revenues	1,085.2	32.9	(31.4)	1,086.7
OPERATING EXPENSES				
Cost of gas sold	274.4	—	—	274.4
Cost of fuel & purchased power	186.9	—	—	186.9
Other operating	263.0	—	(31.2)	231.8
Depreciation & amortization	123.2	20.3	0.4	143.9
Taxes other than income taxes	39.6	1.1	—	40.7
Total operating expenses	887.1	21.4	(30.8)	877.7
OPERATING INCOME	198.1	11.5	(0.6)	209.0
Other income - net	3.1	38.3	(37.4)	4.0
Interest expense	56.5	42.7	(38.0)	61.2
INCOME BEFORE INCOME TAXES	144.7	7.1	—	151.8
Income taxes	58.1	0.9	—	59.0
Equity in earnings of consolidated companies, net of tax	—	86.6	(86.6)	—
NET INCOME	$86.6	$92.8	$(86.6)	$92.8

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

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	$263.6	$33.7	$—	$297.3
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from				
Long-term debt - net of issuance costs	—	99.5	—	99.5
Additional capital contribution from parent	3.5	5.4	(3.5)	5.4
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 flows from 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 investments	(0.2)	—	—	(0.2)
Net change in short-term intercompany notes receivable	—	41.7	(41.7)	—
Net cash flows from 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

Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2011 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	$237.5	$15.1	$—	$252.6
CASH FLOWS FROM FINANCING ACTIVITIES				
Requirements for:				
Dividends to parent	(63.3)	(68.7)	63.3	(68.7)
Retirement of long-term debt, including premiums paid	(0.7)	(0.7)	0.7	(0.7)
Net change in intercompany short-term borrowings	(34.3)	(23.5)	57.8	—
Net change in short-term borrowings	—	(8.7)	—	(8.7)
Net cash flows from financing activities	(98.3)	(101.6)	121.8	(78.1)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from				
Consolidated subsidiary distributions	—	63.3	(63.3)	—
Other investing activities	0.2	0.2	—	0.4
Requirements for:				
Capital expenditures, excluding AFUDC equity	(159.6)	(10.9)	—	(170.5)
Other investments	(0.8)	—	—	(0.8)
Net change in long-term intercompany notes receivable	—	0.7	(0.7)	—
Net change in short-term intercompany notes receivable	23.5	34.3	(57.8)	—
Net cash flows from investing activities	(136.7)	87.6	(121.8)	(170.9)

Net change in cash & cash equivalents	2.5	1.1	—	3.6
Cash & cash equivalents at beginning of period	2.0	0.4	—	2.4
Cash & cash equivalents at end of period	$4.5	$1.5	$—	$6.0

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 and $5.0 million in the three months ended September 30, 2012 and 2011 respectively. For the nine months ended September 30, 2012 and 2011, these taxes totaled $19.1 million and $21.4 million, respectively. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Accruals for Utility & Nonutility Plant

As of September 30, 2012 and December 31, 2011, the Company has accruals related to utility and nonutility plant purchases totaling approximately $7.7 million and $9.2 million, respectively.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Fuels, Inc.
Vectren Fuels, Inc., 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, 2012 and 2011 totaled $24.3 million and $40.2 million, respectively, and for the nine months ended September 30, 2012 and 2011 totaled $82.5 million and $116.0 million, respectively. Amounts owed to Vectren Fuels at September 30, 2012 and December 31, 2011 are included in Payables to other Vectren companies in the Consolidated Balance Sheets.

Miller Pipeline, LLC
Miller Pipeline, LLC (Miller), 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. Miller's customers include Utility Holdings' utilities. Fees incurred by Utility Holdings and its subsidiaries totaled $13.4 million and $17.1 million for the three months ended September 30, 2012 and 2011, respectively, and for the nine months ended September 30, 2012 and 2011 totaled $33.0 million and $32.1 million, respectively. Amounts owed to Miller at September 30, 2012 and December 31, 2011 are included in Payables to other Vectren companies in the Consolidated Balance Sheets.

ProLiance Holdings, LLC (ProLiance)
ProLiance, a nonutility energy marketing affiliate of Vectren and Citizens Energy Group (Citizens), provides services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance's customers include the Company's Indiana utilities as well as Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. On March 17, 2011, an order was received by the IURC providing for ProLiance's continued provision of gas supply services to the Company's Indiana utilities and Citizens Energy Group through March 2016.

Purchases from ProLiance for resale and for injections into storage for the three months ended September 30, 2012 and 2011 totaled $57.2 million and $80.3 million, respectively, and for the nine months ended September 30, 2012 and 2011 totaled $186.9 million and $278.6 million, respectively. Amounts owed to ProLiance at September 30, 2012 and December 31, 2011 for those purchases were $15.4 million and $36.8 million, respectively, and are included in Accounts payable to affiliated companies in the Consolidated Balance Sheets. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

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, 2012 and 2011, Utility Holdings received corporate allocations totaling $8.2 million and $7.3 million, respectively.

For the nine months ended September 30, 2012 and 2011, Utility Holdings received corporate allocations totaling $32.1 million and $33.5 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

On February 1, 2012, the Company issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements. As of December 31, 2011, the Company had reclassified $100 million of short-term borrowings as long-term debt to reflect those borrowings were refinanced with the proceeds received.

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.

9. Legislative Matters

Pipeline Safety Law
On January 3, 2012 the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was signed into law. This new 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 new 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. Those regulations may eventually lead to further regulatory or statutory requirements.

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

95 or other currently authorized recovery mechanisms in Ohio (referenced below).

Indiana Senate Bill 251

In April 2011, Senate Bill 251 was signed into law. While the bill is broad in scope, it allows for cost recovery outside of a base rate proceeding for federal government mandated projects and provides for a voluntary clean energy portfolio standard.

The law applies to both gas and electric utility operations and provides a framework to recover 80 percent of federally mandated operating costs and capital investments through a periodic rate adjustment mechanism outside of a general rate case. Such costs include depreciation, operating and other costs. Construction costs receive a return on investment. The remaining 20 percent of those costs and capital investments are to be deferred for recovery in the utility's next general rate case. The Company is currently evaluating the impact this law may have on its operations, including applicability to expenditures associated with the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution control, including greenhouse gas emissions, among other federally mandated projects and potential projects.

Ohio House Bill 95

In June 2011, Ohio House Bill 95 was signed into law. The law adjusts, among other things, the manner in which gas utilities file for rate changes, including the implementation of base rate changes, alternative rate plans, and automatic rate adjustment mechanisms. Outside of a base rate proceeding, the legislation permits a natural gas company to apply for recovery of a capital expenditure program for infrastructure expansion, upgrade, or replacement; installation, upgrade, or replacement of information technology systems; or any program necessary to comply with government regulation. Once such application is approved, the legislation authorizes deferral of program costs, such as depreciation, property taxes, and debt-related carrying costs. On February 3, 2012, the Company initiated a filing under House Bill 95. This filing requests accounting authority to defer depreciation, debt-related post in service carrying costs and property taxes for its fifteen month capital expenditure program ending on December 31, 2012. The capital expenditure program totals $23.5 million and includes infrastructure expansion and improvements not covered by the Company's distribution replacement rider as well as expenditures necessary to comply with PUCO rules, regulations and orders. The Company's approach is consistent with approaches made by other Ohio utilities. A procedural schedule associated with the filing has been set and all respective responses have been submitted. It is anticipated the PUCO will act on the Company's filing later this year.

10. Environmental Matters

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. On October 5, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. The original August decision vacating CSAPR was made by a three judge panel. EPA is currently seeking reconsideration of the issues raised on appeal before the full appellate panel. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air Regulations").

Mercury and Air Toxics (MATS) Rule

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

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

Conclusions Regarding Air Regulations

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

Utilization of the Company's NOx and SO_2 allowances can be impacted as these 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 is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule and the 2015 requirement imposed by CAIR. Based upon an initial review, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment. However, it is possible some minor modifications to the control equipment, additional operating expenses, and/or the purchase of some allowances could be required. The Company believes that such additional costs, if necessary, would be recoverable under Indiana Senate Bill 251 referenced above.

Notice of Violation Received

The Company received a notice of violation (NOV) from the EPA pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements. At this time the Company is reviewing the potential impact this NOV could have on operating costs. To the extent costs to comply increase, they should be recoverable under Indiana law.

Water

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

Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2013. Depending on the final rule and on the Company's facts and circumstances, capital investments could be in the $40 million range if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations would likely qualify as federally mandated regulatory requirements under Indiana Senate Bill 251 referenced above.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules may not be finalized in 2012 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 would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above.

Climate Change
In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. EPA's PSD and Title V permitting rules for GHG's were recently upheld by the US Court of Appeals for the District of Columbia. In April 2012, the EPA issued its proposed new source performance standards for greenhouse gases applicable to new construction. This proposed rule does not apply to existing sources, such as Vectren's generating facilities. The EPA has not indicated when it intends to propose standards for existing sources.

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

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

trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures would be recoverable from customers through Senate Bill 251.

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 at these sites.

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 reasonably expects to incur totaling approximately $41.7 million ($23.2 million at Indiana Gas and $18.5 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. SIGECO filed a declaratory judgment action against its insurance carriers seeking a judgment finding its carriers liable under the policies for coverage of further investigation and any necessary remediation costs that SIGECO may accrue under the VRP program and/or another site subject to a lawsuit that has been settled. In November 2011, the Court ruled on two motions for summary judgment, finding for SIGECO and against certain insurers on indemnification and defense obligations in the policies at issue. SIGECO has settlement agreements with all known insurance carriers and has recorded approximately $15.2 million of expected 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 some level of additional remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of September 30, 2012 and December 31, 2011, respectively, approximately $4.8 million and $6.5 million of accrued, but not yet spent, costs are included in Other Liabilities related to both the Indiana Gas and SIGECO sites.

11. Rate & Regulatory Matters

Vectren South Electric Base Rate Filing

On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. The IURC issued an order in the case on April 27, 2011. The order provides for an approximate $28.6 million revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent and an overall rate of return of 7.29 percent. The new rates were effective May 3, 2011. The IURC, in its order, denied the Company's request for implementation of the decoupled rate design, which is discussed further below. Addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions would be initiated.

Coal Procurement Procedures

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

Vectren South Electric Fuel Cost Reduction

In the spring of 2011, Vectren South secured contracts for lower coal costs through a formal bidding process. This lower-priced contract coal started being delivered to Vectren's power plants during 2012. On December 5, 2011 within the quarterly FAC filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference will be deferred to a regulatory asset and recovered over a six-year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with a positive impact to customer's rates effective February 1, 2012. The deferred amount includes a reduction in the value of the coal inventory at December 31, 2011 of approximately $17.7 million to reflect existing coal inventory at the new, lower price. Deferrals related to coal purchases in 2012 have totaled approximately $24.7 million, bringing the total deferred balance as of September 30, 2012 to $42.4 million. In addition to coal purchased under these contracts, Vectren South has also recently contracted with Vectren Fuels, Inc. to purchase lower priced spot coal. This spot purchase was found to be reasonable in a recent FAC order.

Vectren South Electric Demand Side Management Program Filing

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

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South service territory that complies with the IURC's energy saving targets. Consistent with the Company's proposal, the order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $1.0 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding discussed earlier.

Vectren South Electric Dense Pack Filing

On September 14, 2011, Vectren South filed a petition with the IURC seeking recovery of and return on the capital investment in dense pack technology to improve the efficiency of its A.B. Brown Generating Station. This investment is expected to be approximately $32 million over the next two years, of which approximately $25.5 million has been invested to date. This technology is expected to allow the A.B. Brown units to run at least 5 percent more efficient, thereby burning less fuel, and reducing fuel costs and emissions of pollutants. In the Company's base rate order issued in April 2011, the IURC authorized deferred accounting treatment associated with this investment. As a result of a subsequent filing by the Company seeking a current recovery mechanism in lieu of the deferred accounting treatment, the IURC issued an order on July 11, 2012, denying the Company's request for a current recovery mechanism stating that dense pack technology does not qualify as advanced technology under the statute. Although the Company believes that the investment does meet the requirements of the statute that would have allowed for timely recovery, it does not plan to appeal the decision and will employ the deferred accounting treatment ordered in the Company's last base rate order discussed earlier.

Vectren North Reporting Location Consolidation Proceeding

Vectren North implemented a reporting location consolidation plan in 2011 and converted certain reporting locations into staging areas throughout the Vectren North territory. On May 26, 2011, the International Brotherhood of Electrical Workers Local 1393, United Steel Workers Locals 12213 and 7441 and others (the "Complainants") filed a formal complaint with the IURC claiming that implementation of the consolidation plan by Vectren North endangers public safety and impairs Vectren North's ability to provide adequate, safe and reliable service. The Complainants asked the IURC to require Vectren North to reopen previously consolidated reporting locations and maintain and staff those locations. A hearing in this case was held in February 2012 and the Company is awaiting the issuance of an order.

12. Fair Value Measurements

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

(In millions)	September 30, 2012		December 31, 2011	
	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,208.4	$1,411.1	$1,208.2	$1,345.7
Short-term borrowings	100.1	100.1	142.8	142.8
Cash & cash equivalents	5.0	5.0	6.0	6.0

For the balance sheet dates presented in these financial statements, the Company had material assets or liabilities recorded at fair value outstanding.

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 would not be expected to have a material effect on the Company's results of operations.

13. Impact of Recently Issued Accounting Principles

Other Comprehensive Income (OCI)

In 2011, the FASB issued new accounting guidance regarding the presentation of comprehensive income within financial statements. The new guidance requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The guidance does not change the items that must be reported in OCI. The new guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and retrospective application is required. The Company adopted this guidance, as amended for condensed quarterly reporting, for the quarterly reporting period ended March 31, 2012. During the periods presented comprehensive income and net income were equal.

Goodwill Testing

In September 2011, the FASB issued new accounting guidance regarding testing goodwill for impairment. The new guidance will allow the Company an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Using the new guidance, the Company no longer would be required to calculate the fair value of a reporting unit unless the Company determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Company considered this option during its quarterly reporting period ended March 31, 2012 and concluded the continuation of the use of a quantitative approach is appropriate.

Fair Value Measurement and Disclosure
In May 2011, the FASB issued accounting guidance to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and International Financial Reporting Standards (IFRS). The amendments are not intended to change the application of the current fair value requirements, but to clarify the application of existing requirements. The guidance does change particular principles or requirements for measuring fair value or disclosing information about fair value measurements. To improve consistency, language has been changed to ensure that U.S. GAAP and IFRS fair value measurement and disclosure requirements are described in the same way. The Company adopted this guidance for its quarterly reporting period ended March 31, 2012. The adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

14. Segment Reporting

The Company's operations consist of regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between 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)	2012	2011	2012	2011
Revenues				
Gas Utility Services	$100.2	$102.1	$508.5	$592.8
Electric Utility Services	167.9	186.7	456.6	492.4
Other Operations	10.2	11.0	30.1	32.9
Eliminations	(10.6)	(10.5)	(29.6)	(31.4)
Total revenues	$267.7	$289.3	$965.6	$1,086.7
Profitability Measure - Net Income (Loss)				
Gas Utility Services	$(2.7)	$(4.8)	$36.1	$33.5
Electric Utility Services	26.6	30.8	59.4	53.1
Other Operations	2.5	1.9	7.0	6.2
Total net income	$26.4	$27.9	$102.5	$92.8

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 564,000 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 310,000 natural gas customers located near Dayton in west central Ohio.

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 2011 annual report filed on Form 10-K.

In the third quarter of 2012, Utility Holdings' earnings were $26.4 million, compared to $27.9 million in 2011. In the nine months ended September 30, 2012, the Utility Group earned $102.5 million, compared to the $92.8 million in 2011. Increased year-over-year results for the nine month periods reflect, among other things, the impacts of new electric base rates implemented on May 3, 2011 and lower interest expense as a result of refinancing activity in the last quarter of 2011 and first quarter of 2012. The decrease in the quarter-over-quarter results generally reflects lower earnings from electric utility operations associated with higher operating expenses and lower small customer margins.

Gas Utility Services
During the third quarter of 2012, Gas Utility Services operated at a seasonal loss of $2.7 million, compared to a loss of $4.8 million in the third quarter of 2011. In the nine months ended September 30, 2012, gas utility operations earned $36.1 million, compared to earnings of $33.5 million in 2011. Both the quarter and year to date period reflect increased earnings from investment in bare steel cast iron replacement activities and favorable interest expense due to the recent refinancing activity.

Electric Utility Services
During the third quarter of 2012, Electric Utility earnings were $26.6 million, compared to $30.8 million in the third quarter of 2011. Electric operations earned $59.4 million year to date in 2012, compared to earnings of $53.1 million for the nine months ended September 30, 2011. Improved year to date results in 2012 reflect increased electric margin, primarily from base rate changes and lower interest costs. The decrease in the quarter-over-quarter results generally reflects higher operating expenses and lower customer margins from conservation beyond approved lost margin recovery mechanisms, which more than offset slightly warmer weather in the quarter as compared to the same quarter in 2011.

Other Utility Operations
In the third quarter of 2012, earnings from Other Utility operations were $2.5 million, compared to $1.9 million in 2011. In the nine months ended September 30, 2012, earnings from these operations were $7.0 million, compared to $6.2 million in 2011. The 2011 year to date results include a $1.4 million unfavorable tax adjustment. In addition, variability in the earnings of the segment occurs as the allocation of shared asset costs changes.

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, 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.

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)	2012	2011	2012	2011
Gas utility revenues	$100.2	$102.1	$508.5	$592.8
Cost of gas sold	28.1	30.5	197.0	274.4
Total gas utility margin	$72.1	$71.6	$311.5	$318.4
Margin attributed to:				
Residential & commercial customers	$58.5	$58.4	$263.1	$268.4
Industrial customers	11.9	11.5	40.8	41.0
Other	1.7	1.7	7.6	9.0
Total gas utility margin	$72.1	$71.6	$311.5	$318.4
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	$6.3	$6.5	$57.3	$71.0
Industrial customers	25.1	20.7	77.2	70.6
Total sold & transported volumes	$31.4	$27.2	$134.5	$141.6

Gas Utility margins were $72.1 million and $311.5 million for the for the three and nine months ended September 30, 2012, and compared to 2011 increased $0.5 million quarter over quarter and decreased $6.9 million year to date. The impact of low natural gas prices and mild weather on revenue taxes, late and reconnect fees, and volumetric pass through costs decreased gas utility margin $1.0 million quarter over quarter and $8.4 million year to date. Returns generated on investments in bare steel/ cast iron and distribution riser replacement in Ohio increased margins $0.6 million in the quarter and $2.0 million year to date in 2012 compared to the prior year. With rate designs that substantially limit the impact of weather on margin, temperatures that were 71 percent of normal in Indiana and 83 percent of normal in Ohio during the peak winter heating season in early 2012 had a significant impact on volumes sold, but only a slightly negative impact on margin, reducing margin $0.7 million year over year. Excluding the impact of passthrough costs, large customer margins increased $0.7 million in the quarter, and due to the warm winter weather, have increased $0.4 million year over year.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2012	2011	2012	2011
Electric utility revenues	$167.9	$186.7	$456.6	$492.4
Cost of fuel & purchased power	52.9	67.1	144.6	186.9
Total electric utility margin	$115.0	$119.6	$312.0	$305.5
Margin attributed to:				
Residential & commercial customers	$76.9	$82.1	$201.3	$199.1
Industrial customers	27.5	27.7	79.6	76.6
Other customers	1.9	2.2	5.6	5.7
Subtotal: retail	$106.3	$112.0	$286.5	$281.4
Wholesale power & transmission system margin	8.7	7.6	25.5	24.1
Total electric utility margin	$115.0	$119.6	$312.0	$305.5
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	813.8	863.5	2,138.2	2,223.0

Industrial customers	732.5	731.8	2,127.6	2,074.6
Other customers	5.3	5.6	16.0	16.3
Total retail volumes sold	1,551.6	1,600.9	4,281.8	4,313.9

Retail

Electric retail utility margins were $106.3 million and $286.5 million for the three and nine months ended September 30, 2012, and compared to 2011 decreased by $5.7 million in the quarter and increased $5.1 million year to date. The year to date increase is driven primarily by $10.0 million of incremental margin across all customer classes from new base rates effective May 3, 2011. Year to date, electric margin also benefited from higher volumes sold to industrial customers. However, margin was lower in the quarter and year to date on refunds resulting from statutory net operating income limits and lower third quarter small customer margins. The small customer margins were lower as a result of conservation beyond approved lost margin recovery mechanisms, which more than offset slightly warmer weather in the quarter as compared to the same quarter in 2011.

Electric results, which are not protected by weather mechanisms, were positively impacted in the third quarter of 2012 as a result of warm weather. In the third quarter of 2012, cooling temperatures were 119 percent of normal; this compares to the third quarter of 2011 when cooling temperatures were 114 percent of normal. In the third quarter of 2012, the increase in electric margin, net of amounts refunded to customers as discussed below, compared to normal temperatures was estimated to be $2.4 million. On a year to date basis, cooling temperatures that were 131 percent of normal offset the impact of mild first quarter heating weather. Management estimates the weather impact on electric margin year to date, net of refunds to customers, to be $1.0 million favorable.

Indiana regulation includes a statutory mechanism that can limit a utility's rolling twelve month net operating income to that authorized in its last general rate order, as adjusted for previous net operating income levels that were below authorized levels. Should weather or other factors continue to increase net operating income in future periods, the full benefit of those favorable impacts on the company's electric utility may continue to be limited by the statutory earnings test.

Margin from Wholesale Electric Activities

Periodically, generation capacity is in excess of native load. The Company markets and sells this unutilized generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales occur into the MISO Day Ahead and Real Time markets. Further detail of Wholesale activity follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2012	2011	2012	2011
Off-system sales	$1.0	$0.7	$4.7	$5.1
Transmission system sales	7.7	6.9	20.8	19.0
Total wholesale margin	$8.7	$7.6	$25.5	$24.1

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. Margin associated with these projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $7.7 million during the three months September 30, 2012, compared to $6.9 million for the same period in 2011. Year to date in 2012 margins were $20.8 million compared to $19.0 million in the prior year. The increases in transmission system revenue is principally due to the increased investment in qualifying projects.

One such project currently under construction meeting these expansion plan criteria is an interstate 345 Kv transmission line that will connect Vectren's A.B. Brown Generating Station to a station in Indiana owned by Duke Energy to the north and to a station in Kentucky owned by Big Rivers Electric Corporation to the south. During the construction of these transmission assets and while these assets are in service, SIGECO will recover an approximate 10 percent return, inclusive of the FERC approved equity rate of return of 12.38 percent, on capital investments through a rider mechanism which is projected annually and reconciled the following year based on actual results. Of the total investment, which is expected to approximate $110 million, the Company has invested approximately $98.5 million as of September 30, 2012. The north leg of this expansion was placed in service in November 2010, and the south leg of this project is expected to be operational later in 2012.

In the third quarter of 2012 margin from off system sales was $1.0 million compared to $0.7 million in 2011. For the nine months ended September 30, 2012, margin from off-system sales was $4.7 million, compared to $5.1 million for the nine months ended

September 30, 2011. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million be shared equally with customers. This compares to a $10.5 million sharing threshold established in 2007. The year to date period reflects lower volumes sold, offset by the impacts of sharing which increased margin $0.6 million. Off-system sales totaled 184.4 GWh and 469.4 GWh during the nine months ended September 30, 2012 and 2011, respectively, reflecting reduced opportunities in 2012 due to unfavorable weather conditions when excess generation is more prevalent and the low cost of natural gas.

Operating Expenses

Other Operating
For the three months ended September 30, 2012 operating expenses increased $5.1 million driven primarily by the timing of electric utility operating costs associated with planned outages and increased pipeline integrity management work in the Ohio natural gas service territory. For the nine months ended September 30, 2012, other operating expenses were $229.5 million, a decrease of $2.3 million, compared to 2011. The decrease is primarily driven by lower pass through costs and uncollectible accounts expenses associated with gas utility operations. The lower expenses are driven by lower, mostly weather-related, volumes sold and lower gas costs. Continuous improvement initiatives throughout the Utility Group are being implemented to limit growth in operating expenses over the coming years. The Company estimates that year to date in 2012 these initiatives have resulted in sustainable savings of over $4 million. Examples of the initiatives implemented thus far in 2012 include improved processes that have allowed the company to become more efficient in completing work and thereby reduce labor costs, and recent amendments to postretirement medical plans that provide better access to benefits for company retirees at lower costs. These sustainable savings have aided in offsetting planned increases in energy delivery related operating expenses. Operating costs overall in 2012 are expected to be about flat to 2011 on an annual basis.

Depreciation & Amortization
For the three and nine months ended September 30, 2012, depreciation and amortization expense was $46.3 million and $142.7 million, respectively. Depreciation expense decreased $1.5 million in the quarter and $1.2 million year to date. Both the year to date and quarter reflect reductions associated with regulatory orders, offset by increased plant placed in service in gas and electric operations.

Taxes Other Than Income Taxes
In the 2012 third quarter taxes other than income taxes were $11.5 million and year to date in 2012 were $39.0 million. The year to date decrease of $1.7 million compared to the prior year was primarily due to lower usage taxes associated with lower gas and fuel costs. These expenses are offset dollar-for-dollar with lower gas utility and electric utility revenues.

Other Income-Net

Other income-net reflects income of $2.3 million for the third quarter and $5.2 million year to date in 2012. Increases of $2.2 million in the quarter and $1.2 million year to date compared to 2011 primarily reflect earnings on assets that fund benefit plans.

Interest Expense

Interest expense was $17.8 million and $53.5 million, respectively for the three and nine months ended September 30, 2012. Interest expense decreased $2.6 million in the quarter and $7.7 million year to date compared to 2011. The lower expense both in the quarter and year to date reflects fourth quarter of 2011 refinancing activity in which $250 million of long-term debt with a 6.625 percent interest rate matured and was replaced with $150 million of new long-term debt with an average interest rate of 5.12 percent and $100 million of short-term borrowings. During the fourth quarter of 2011, the Company also called $96.2 million of long-term debt at a rate of 5.95 percent and replaced that issuance in February 2012 with new debt at a rate of 5.0 percent.

Income Taxes

In the nine months ended September 30, 2012, federal and state income taxes were $62.0 million, an increase of $3.0 million compared to the prior year. In the quarter federal and state taxes decreased $2.2 million. The quarterly and year to date changes are primarily due to variances in pre-tax income. The year to date period in 2011 also included a one-time, unfavorable tax adjustment of $1.4 million.

Legislative Matters

Pipeline Safety Law

On January 3, 2012 the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was signed into law. This new 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 new 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. Those regulations may eventually lead to further regulatory or statutory requirements.

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

Indiana Senate Bill 251

In April 2011, Senate Bill 251 was signed into law. While the bill is broad in scope, it allows for cost recovery outside of a base rate proceeding for federal government mandated projects and provides for a voluntary clean energy portfolio standard.

The law applies to both gas and electric utility operations and provides a framework to recover 80 percent of federally mandated operating costs and capital investments through a periodic rate adjustment mechanism outside of a general rate case. Such costs include depreciation, operating and other costs. Construction costs receive a return on investment. The remaining 20 percent of those costs and capital investments are to be deferred for recovery in the utility's next general rate case. The Company is currently evaluating the impact this law may have on its operations, including applicability to expenditures associated with the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution control, including greenhouse gas emissions, among other federally mandated projects and potential projects.

Ohio House Bill 95

In June 2011, Ohio House Bill 95 was signed into law. The law adjusts, among other things, the manner in which gas utilities file for rate changes, including the implementation of base rate changes, alternative rate plans, and automatic rate adjustment mechanisms. Outside of a base rate proceeding, the legislation permits a natural gas company to apply for recovery of a capital expenditure program for infrastructure expansion, upgrade, or replacement; installation, upgrade, or replacement of information technology systems; or any program necessary to comply with government regulation. Once such application is approved, the legislation authorizes deferral of program costs, such as depreciation, property taxes, and debt-related carrying costs. On February 3, 2012, the Company initiated a filing under House Bill 95. This filing requests accounting authority to defer depreciation, debt-related post in service carrying costs and property taxes for its fifteen month capital expenditure program ending on December 31, 2012. The capital expenditure program totals $23.5 million and includes infrastructure expansion and improvements not covered by the Company's distribution replacement rider as well as expenditures necessary to comply with

PUCO rules, regulations and orders. The Company's approach is consistent with approaches made by other Ohio utilities. A procedural schedule associated with the filing has been set and all respective responses have been submitted. It is anticipated the PUCO will act on the Company's filing later this year.

Environmental Matters

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. On October 5, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. The original August decision vacating CSAPR was made by a three judge panel. EPA is currently seeking reconsideration of the issues raised on appeal before the full appellate panel. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air Regulations").

Mercury and Air Toxics (MATS) Rule

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

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

Conclusions Regarding Air Regulations

To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the

Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining

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

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

The Company is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule and the 2015 requirement imposed by CAIR. Based upon an initial review, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment. However, it is possible some minor modifications to the control equipment, additional operating expenses, and/or the purchase of some allowances could be required. The Company believes that such additional costs, if necessary, would be recoverable under Indiana Senate Bill 251 referenced above.

Notice of Violation Received

The Company received a notice of violation (NOV) from the EPA pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements. At this time the Company is reviewing the potential impact this NOV could have on operating costs. To the extent costs to comply increase, they should be recoverable under Indiana law.

Water

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

Coal Ash Waste Disposal & Ash Ponds

In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules may not be finalized in 2012 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 would likely qualify as federally mandated regulatory requirements and be recovered under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. EPA's PSD and Title V permitting rules for GHG's were recently upheld by the US Court of Appeals for the District of Columbia. In April 2012, the EPA issued its proposed new source performance standards for greenhouse gases applicable to new construction. This proposed rule does not apply to existing sources, such as Vectren's generating facilities. The EPA has not indicated when it intends to propose standards for existing sources.

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 CO2 and other greenhouse gases or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures would be recoverable from customers through Senate Bill 251.

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 at these sites.

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 reasonably expects to incur totaling approximately $41.7 million ($23.2 million at Indiana Gas and $18.5 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. SIGECO filed a declaratory judgment action against its insurance carriers seeking a judgment finding its carriers liable under the policies for coverage of further investigation and any necessary remediation costs that SIGECO may accrue under the VRP program and/or another site subject to a lawsuit that has been settled. In November 2011, the Court ruled on two motions for summary judgment, finding for SIGECO and against certain insurers on indemnification and defense obligations in the policies at issue. SIGECO has settlement agreements with all known insurance carriers and has recorded approximately $15.2 million of expected 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 some level of additional remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of September 30, 2012 and December 31, 2011, respectively, approximately $4.8 million and $6.5 million of accrued, but not yet spent, costs are included in Other Liabilities related to both the Indiana Gas and SIGECO sites.

Rate & Regulatory Matters

Vectren South Electric Base Rate Filing

On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. The IURC issued an order in the case on April 27, 2011. The order provides for an approximate $28.6 million revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent and an overall rate of return of 7.29 percent. The new rates were effective May 3, 2011. The IURC, in its order, denied the Company's request for implementation of the decoupled rate design, which is discussed further below. Addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions would be initiated.

Coal Procurement Procedures

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

Vectren South Electric Fuel Cost Reduction

In the spring of 2011, Vectren South secured contracts for lower coal costs through a formal bidding process. This lower-priced contract coal started being delivered to Vectren's power plants during 2012. On December 5, 2011 within the quarterly FAC filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference will be deferred to a regulatory asset and recovered over a six-year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012,

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with a positive impact to customer's rates effective February 1, 2012. The deferred amount includes a reduction in the value of the coal inventory at December 31, 2011 of approximately $17.7 million to reflect existing coal inventory at the new, lower price. Deferrals related to coal purchases in 2012 have totaled approximately $24.7 million, bringing the total deferred balance as of September 30, 2012 to the expected level of $42.4 million. In addition to coal purchased under these contracts, Vectren South has also recently contracted with Vectren Fuels, Inc. to purchase lower priced spot coal. This spot purchase was found to be reasonable in a recent FAC order.

Vectren South Electric Demand Side Management Program Filing

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

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

Vectren South Electric Dense Pack Filing

On September 14, 2011, Vectren South filed a petition with the IURC seeking recovery of and return on the capital investment in dense pack technology to improve the efficiency of its A.B. Brown Generating Station. This investment is expected to be approximately $32 million over the next two years, of which approximately $25.5 million has been invested to date. This technology is expected to allow the A.B. Brown units to run at least 5 percent more efficient, thereby burning less fuel, and reducing fuel costs and emissions of pollutants. In the Company's base rate order issued in April 2011, the IURC authorized deferred accounting treatment associated with this investment. As a result of a subsequent filing by the Company seeking a current recovery mechanism in lieu of the deferred accounting treatment, the IURC issued an order on July 11, 2012, denying the Company's request for a current recovery mechanism stating that dense pack technology does not qualify as advanced technology under the statute. Although the Company believes that the investment does meet the requirements of the statute that would have allowed for timely recovery, it does not plan to appeal the decision and will employ the deferred accounting treatment ordered in the Company's last base rate order discussed earlier.

Vectren North Reporting Location Consolidation Proceeding

Vectren North implemented a reporting location consolidation plan in 2011 and converted certain reporting locations into staging areas throughout the Vectren North territory. On May 26, 2011, the International Brotherhood of Electrical Workers Local 1393, United Steel Workers Locals 12213 and 7441 and others (the "Complainants") filed a formal complaint with the IURC claiming that implementation of the consolidation plan by Vectren North endangers public safety and impairs Vectren North's ability to provide adequate, safe and reliable service. The Complainants asked the IURC to require Vectren North to reopen previously consolidated reporting locations and maintain and staff those locations. A hearing in this case was held in February 2012 and the Company is awaiting the issuance of an order.

Impact of Recently Issued Accounting Guidance

Other Comprehensive Income (OCI)

In 2011, the FASB issued new accounting guidance regarding the presentation of comprehensive income within financial statements. The new guidance requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. The guidance does not change the items that must be reported in OCI. The new guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and retrospective application is required. The Company adopted this guidance, as amended for condensed quarterly reporting, for the quarterly reporting period ended March 31, 2012. During the periods presented comprehensive income and net income were equal.

Goodwill Testing

In September 2011, the FASB issued new accounting guidance regarding testing goodwill for impairment. The new guidance will allow the Company an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Using the new guidance, the Company no longer would be required to calculate the fair value of a reporting unit unless the Company determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Company considered this option during its quarterly reporting period ended March 31, 2012 and concluded the continuation of the use of a quantitative approach is appropriate.

Fair Value Measurement and Disclosure

In May 2011, the FASB issued accounting guidance to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and International Financial Reporting Standards (IFRS). The amendments are not intended to change the application of the current fair value requirements, but to clarify the application of existing requirements. The guidance does change particular principles or requirements for measuring fair value or disclosing information about fair value measurements. To improve consistency, language has been changed to ensure that U.S. GAAP and IFRS fair value measurement and disclosure requirements are described in the same way. The Company adopted this guidance for its quarterly reporting period ended March 31, 2012. The adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

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 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, inclusive of current maturities, with a par value of $821 million and short-term obligations totaling $100 million were outstanding at September 30, 2012. 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 outstanding at September 30, 2012, was $387 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, 2012, are A-/A3 as rated by Standard and Poor's Ratings Services (Standard and Poor’s) and Moody’s Investors Service (Moody’s), respectively. The credit ratings on SIGECO's secured debt are A/A1. Utility Holdings’ commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody’s and Standard and Poor’s is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor’s and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 50-60 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 53 percent of long-term capitalization at both December 31, 2011 and September 30, 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, 2012, 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. The Company anticipates funding future capital expenditures and dividends primarily through internally generated funds. Available liquidity has been enhanced by the extension of bonus depreciation legislation. However, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline modernization; and expanded EPA regulations for air, water, and fly ash. The timing and amount of such investments depends on a variety of factors, including forecasted liquidity. The company plans to enhance its liquidity as needed by accessing the capital markets.

Consolidated Short-Term Borrowing Arrangements

At September 30, 2012, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $250 million was available at September 30, 2012. This short-term borrowing facility was renewed in November 2011 and 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. Liquidity was increased by the $100 million Utility Holdings debt issuance in February 2012, the net proceeds of which were used to repay short-term indebtedness.

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)	2012	2011
Nine Months Ended September 30		
Balance Outstanding	$100.1	$38.3
Weighted Average Interest Rate	0.46%	0.41%
Nine Months Ended September 30 Average		
Balance Outstanding	$69.5	$14.0
Weighted Average Interest Rate	0.48%	0.40%
Maximum Month End Balance Outstanding	$100.1	$42.5

(In millions)	2012	2011
Quarterly Average - September 30		
Balance Outstanding	$63.8	$18.8
Weighted Average Interest Rate	0.47%	0.41%
Maximum Month End Balance Outstanding	$100.1	$38.3

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Utility Holdings 2012 Debt Issuance

On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements. As of December 31, 2011, the Company had reclassified $100 million of short-term borrowings as long-term debt to reflect that those borrowings were to be refinanced with the proceeds received from the February 1, 2012 long-term debt issuance.

Potential Uses of Liquidity

Planned Capital Expenditures
Utility capital expenditures are estimated at $67 million for the remainder of 2012.

Pension Funding Obligations
Vectren's management currently estimates contributing $15 million to qualified pension plans in 2012, of which a portion may be funded by Utility Holdings; however, none was funded by Utility Holdings during the nine months ended September 30, 2012.

Other Letters of Credit
As of September 30, 2012, 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, 2012.

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 $297.3 million and $252.6 million during the nine months ended September 30, 2012 and 2011, respectively. The $44.7 million increase in operating cash flow in 2012 compared to 2011 is primarily due to increased cash flow from working capital, increased earnings and reduced cash needs for contributions to Vectren's pension plans in 2012 compared to 2011.

Financing Cash Flow
Net cash flow required for financing activities was $113.8 million and $78.1 million during the nine months ended September 30, 2012 and 2011, respectively. Financing activity in 2012 primarily reflects the $100 million debt issuance, the payment of dividends, and repayment of more short-term borrowings in 2012.

Investing Cash Flow
Cash flow required for investing activities was $184.5 million and $170.9 million during the nine months ended September 30, 2012 and 2011, respectively. The current year period reflects an approximate $16 million increase in

cash required for capital expenditures. Warm, dry weather during the first nine months of 2012 allowed for greater capital expenditures for bare steel/cast iron and electric transmission projects.

Forward-Looking Information

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

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to fossil fuel costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks or other similar occurrences could adversely affect Vectren's facilities, operations, financial condition and results of operations.
- Increased competition in the energy industry, including the effects of industry restructuring and unbundling.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under traditional regulation, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas 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.
- 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.

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- 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 invest in and develop new opportunities, including but not limited to, Vectren's coal mining, gas marketing, and energy infrastructure strategies.

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. 2011 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, 2012, 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, 2012, 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, 2012, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

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 2011 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

* Users of the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections. The financial information contained in the XBRL-related documents is “unaudited” and “unreviewed.”

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 9, 2012

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

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

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