VECTREN UTILITY HOLDINGS INC
Form 10-Q
November 13, 2018

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, 2018
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
Emerging Growth Company o	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards pursuant to Section 13(a) of the Exchange Act. 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, 2018
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: David E. Parker Director, Investor Relations vvcir@vectren.com

Definitions

The Administration: Executive Office of the President of the United States	IRP: Integrated Resource Plan
AFUDC: allowance for funds used during construction	IURC: Indiana Utility Regulatory Commission
ASC: Accounting Standards Codification	kV: Kilovolt
ASU: Accounting Standards Update	MCF / BCF: thousands / billions of cubic feet
BTU / MMBTU: British thermal units / millions of BTU	MDth / MMDth: thousands / millions of dekatherms
DOT: Department of Transportation	MISO: Midcontinent Independent System Operator
EPA: Environmental Protection Agency	MW: megawatts
FAC: Fuel Adjustment Clause	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

GAAP: Generally Accepted Accounting Principles

GCA: Gas Cost Adjustment

IDEM: Indiana Department of Environmental Management

OUCC: Indiana Office of the Utility Consumer Counselor

PHMSA: Pipeline and Hazardous Materials Safety Administration

PUCO: Public Utilities Commission of Ohio

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, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash & cash equivalents	$ 7.0	$ 9.8
Accounts receivable - less reserves of $3.2 & $3.9, respectively	82.2	109.5
Accrued unbilled revenues	42.3	123.7
Inventories	100.8	117.5
Recoverable fuel & natural gas costs	7.8	19.2
Prepayments & other current assets	37.2	32.7
Total current assets	277.3	412.4
Utility Plant		
Original cost	7,394.5	7,015.4
Less: accumulated depreciation & amortization	2,850.9	2,738.7
Net utility plant	4,543.6	4,276.7
Investments in unconsolidated affiliates	0.2	0.2
Other investments	30.7	26.7
Nonutility plant - net	202.5	198.6
Goodwill	205.0	205.0
Regulatory assets	366.6	314.0
Other assets	64.0	64.2
TOTAL ASSETS	$ 5,689.9	$ 5,497.8

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, 2018	December 31, 2017
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 125.2	$ 221.8
Payables to other Vectren companies	29.2	33.3
Accrued liabilities	176.9	154.0
Short-term borrowings	225.3	179.5
Current maturities of long-term debt	—	100.0
Total current liabilities	556.6	688.6
Long-Term Debt - Net of Current Maturities	1,729.6	1,479.5
Deferred Credits & Other Liabilities		
Deferred income taxes	483.1	457.5
Regulatory liabilities	938.7	937.2
Deferred credits & other liabilities	220.5	212.2
Total deferred credits & other liabilities	1,642.3	1,606.9
Commitments & Contingencies (Notes 9 - 12)		
Common Shareholder's Equity		
Common stock (no par value)	879.2	877.5
Retained earnings	882.2	845.3
Total common shareholder's equity	1,761.4	1,722.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 5,689.9	$ 5,497.8

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
OPERATING REVENUES				
Gas utility	$122.1	$120.4	$600.7	$557.2
Electric utility	160.0	159.2	437.4	433.0
Other	0.1	0.1	0.2	0.2
Total operating revenues	282.2	279.7	1,038.3	990.4
OPERATING EXPENSES				
Cost of gas sold	24.5	23.9	211.4	174.0
Cost of fuel & purchased power	47.5	44.1	137.7	128.8
Other operating	83.5	82.0	265.6	250.4
Depreciation & amortization	63.4	59.0	186.3	174.3
Taxes other than income taxes	13.5	12.6	47.5	40.1
Total operating expenses	232.4	221.6	848.5	767.6
OPERATING INCOME	49.8	58.1	189.8	222.8
Other income - net	9.2	8.1	27.9	21.4
Interest expense	20.3	18.3	60.3	53.5
INCOME BEFORE INCOME TAXES	38.7	47.9	157.4	190.7
Income taxes	5.7	17.1	24.6	68.5
NET INCOME	$33.0	$30.8	$132.8	$122.2

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,	
	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$132.8	$122.2
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	186.3	174.3
Deferred income taxes & investment tax credits	11.1	72.0
Expense portion of pension & postretirement benefit cost	3.3	2.6
Provision for uncollectible accounts	4.7	4.0
Other non-cash items - net	1.4	(3.3)
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	104.0	90.0
Inventories	16.7	(1.4)
Recoverable/refundable fuel & natural gas costs	11.4	—
Prepayments & other current assets	(4.3)	(5.8)
Accounts payable, including to Vectren companies & affiliated companies	(111.0)	(79.0)
Accrued liabilities	22.9	(1.8)
Cash to fund pension & postretirement plans	(6.7)	—
Changes in noncurrent assets	(33.1)	(26.3)
Changes in noncurrent liabilities	(18.3)	(9.3)
Net cash from operating activities	321.2	338.2
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt - net of issuance costs	249.3	99.2
Additional capital contribution	1.7	44.6
Requirements for:		
Dividends to parent	(96.0)	(92.5)
Retirement of long-term debt	(100.0)	—
Net change in short-term borrowings	45.8	17.3
Net cash from financing activities	100.8	68.6
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other collections	—	2.8
Requirements for:		
Capital expenditures, excluding AFUDC equity	(424.8)	(411.7)
Other costs	—	(2.4)
Changes in restricted cash	—	0.9
Net cash from investing activities	(424.8)	(410.4)
Net change in cash & cash equivalents	(2.8)	(3.6)
Cash & cash equivalents at beginning of period	9.8	9.4
Cash & cash equivalents at end of period	$7.0	$5.8

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

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

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000, to serve as the intermediate holding company for Vectren Corporation’s (Vectren or the Company's parent) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company 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 the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 598,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,000 electric customers and approximately 112,000 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 320,000 natural gas customers located near Dayton in west-central Ohio.

Merger with CenterPoint Energy, Inc.
On April 21, 2018, Vectren entered into an Agreement and Plan of Merger (the “Merger Agreement”), with CenterPoint Energy, Inc., a Texas corporation (“CenterPoint”), and Pacer Merger Sub, Inc., an Indiana corporation and wholly owned subsidiary of CenterPoint (“Merger Sub”). Pursuant to the Merger Agreement, and subject to the terms and conditions of the agreement, Merger Sub will merge with and into Vectren (the “Merger”), with Vectren continuing as the surviving corporation and becoming a wholly owned subsidiary of CenterPoint.

Subject to the terms and conditions in the Merger Agreement, upon closing, each share of common stock of Vectren shall be converted into the right to receive $72.00 in cash without interest.

Vectren, CenterPoint and Merger Sub each have made various representations, warranties and covenants in the Merger Agreement. Among other things, Vectren has agreed, subject to certain exceptions, to conduct its businesses in the ordinary course, consistent with past practice, from the date of the Merger Agreement until closing, and not to take certain actions prior to the closing of the Merger without the approval of CenterPoint. Vectren has made certain additional customary covenants, including, subject to certain exceptions: (1) to cause a meeting of Vectren's shareholders to be held to consider approval of the Merger Agreement, (2) not to solicit proposals relating to alternative business combination transactions and not to participate in discussions concerning, or furnish information in connection with, alternative business combination transactions and (3) not to withdraw its recommendation to Vectren’s shareholders regarding the Merger. In addition, subject to the terms of the Merger Agreement, Vectren, CenterPoint and Merger Sub are required to use reasonable best efforts to obtain all required regulatory approvals, which will include clearance under federal antitrust laws and certain approvals by federal regulatory bodies, including the Federal Energy Regulatory Commission ("FERC"), subject to certain exceptions, including such efforts not result in a "Burdensome Condition" (as defined in the Merger Agreement). While approval of the Merger Agreement is not required by the Indiana Utility Regulatory Commission ("IURC") or the Public Utilities Commission of Ohio ("PUCO"), informational filings have been made with each commission.

Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of Vectren, (2) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (3) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (4) absence of any law or order prohibiting the consummation of the Merger and (5) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to Vectren and its subsidiaries.

The Merger Agreement contains certain termination rights for both Vectren and CenterPoint, including if the Merger is not consummated by April 21, 2019 (subject to extension for an additional six months if all conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for each of Vectren and CenterPoint, and provides that, upon termination of the Merger Agreement under certain specified circumstances, CenterPoint would be required to pay a termination fee of $210 million to Vectren, and under other specified circumstances Vectren would be required to pay CenterPoint a termination fee of $150 million.

On June 15, 2018, Vectren and CenterPoint submitted their filings with the FERC and initiated informational proceedings with regulators in Indiana and Ohio. Further, on June 18, 2018, Vectren and CenterPoint submitted their filings pursuant to the Hart-Scott-Rodino Act and the Federal Communications Commission. On June 26, 2018, CenterPoint and Vectren received notice from the Federal Trade Commission granting early termination of the waiting period under the Hart-Scott-Rodino Act.
On July 16, 2018, Vectren filed a definitive proxy statement, and a Form 8-K including supplemental disclosures to the proxy statement, with the Securities and Exchange Commission in connection with the Merger. On July 24, 2018, the Federal Communications Commission provided the final approvals for the transfer of control of the Vectren subsidiaries which hold radio licenses. At the special shareholders meeting held on August 28, 2018, the Merger Agreement and the Merger, as well as other matters relating to the proposed Merger, were voted on and approved by Vectren's shareholders. On October 5, 2018, the FERC issued an order indicating its approval of the Merger. In Indiana, the IURC held a hearing on October 17, 2018 on Vectren's informational filing. Final briefs are to be filed by December 21, 2018, and an order is expected in early 2019. A similar informational filing was made in Ohio and, though a hearing before the PUCO is not anticipated, an order is expected in early 2019, as well. As of November 6, 2018, seven purported Vectren shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in Vectren's proxy statement in connection with the Merger as discussed in Note 9. Subject to receipt of remaining approvals, Vectren continues to anticipate that the closing of the Merger will occur no later than the first quarter of 2019.

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 interim 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, 2017, filed with the Securities and Exchange Commission on March 8, 2018, 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. Revenue

In May 2014, the FASB issued new accounting guidance, ASC 606, Revenue from Contracts with Customers, to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires enhanced disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized.

On January 1, 2018, the Company adopted the new accounting standard and all the related amendments (“new revenue standard”) to all contracts not complete at the date of initial application using the modified retrospective method, which resulted in no cumulative adjustment to retained earnings. The Company expects ongoing application to continue to be immaterial to financial condition and net income. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods.

Substantially all the Company’s revenues are within the scope of the new revenue standard.

Revenue Policy
Revenue is recognized when obligations under the terms of a contract with the customer are satisfied. Revenue is measured as the amount of consideration the Company expects to receive in exchange for transferring goods or providing services. The satisfaction of performance obligation occurs when the transfer of goods and services occur, which may be at a point in time or over time; resulting in revenue being recognized over the course of the underlying contract or at a single point in time based upon the delivery of services to customers. The Company determines that disaggregating revenue into customer class, as discussed further below, achieves the disclosure objective to depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

The Company provides commodity service to customers at rates, charges, and terms and conditions included in tariffs approved by regulators. The Company’s utilities bill customers on a monthly basis and have the right to consideration from customers in an amount that corresponds directly with the performance obligation satisfied to date. The performance obligation is satisfied and revenue is recognized upon the delivery of services to customers. The Company records revenues for services and goods delivered but not billed at the end of an accounting period in Accrued unbilled revenues, derived from estimated unbilled consumption and tariff rates. The Company's revenues are also adjusted for the effects of regulation including tracked operating expenses, infrastructure replacement mechanisms, decoupling mechanisms, and lost margin recovery. Decoupling and lost margin recovery mechanisms are considered alternative revenue programs, which are excluded from the scope of the new revenue standard. Revenues from alternative revenue programs are not material to any reporting period. Customers are billed monthly and payment terms, set by the regulator, require payment within a month of billing. The Company's revenues are not subject to significant returns, refunds, or warranty obligations.

In the following table, the Company's revenue is disaggregated by customer class.

(In millions)	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Gas Utility Services		
Residential	$ 80.9	$ 400.9
Commercial	23.7	136.4
Industrial	15.6	56.1
Other	1.9	7.3
Total Gas Utility Services	$ 122.1	$ 600.7
Electric Utility Services		
Residential	$ 63.1	$ 163.5

Commercial	40.3	112.1
Industrial	43.3	121.7
Other	13.3	40.1
Total Electric Utility Services	$ 160.0	$ 437.4

Contract Balances

The Company does not have any material contract balances (right to consideration for services already provided or obligations to provide services in the future for consideration already received) as of January 1, 2018 or September 30, 2018. Substantially all of the Company's accounts receivable results from contracts with customers.

Remaining Performance Obligations

In accordance with the optional exemptions available under the new revenue standard, the Company has not disclosed the value of unsatisfied performance obligations from contracts for which revenue is recognized at the amount to which the Company has the right to invoice for goods provided and services performed. Substantially all of the Company's contracts with customers are eligible for this exemption.

4. Subsidiary Guarantor and Consolidating Information

The Company’s three operating utility companies, SIGECO, Indiana Gas, and VEDO, are guarantors of the Company's $400 million in short-term credit facilities, of which $225 million was outstanding at September 30, 2018, and the Company's $1.345 billion in unsecured senior notes outstanding at September 30, 2018. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. However, it 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 wholly owned, separate from the parent company’s operations is required. Following are condensed 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, 2018 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$ 5.2	$ 1.8	$ —	$ 7.0
Accounts receivable - less reserves	82.0	0.2	—	82.2
Intercompany receivables	7.5	167.6	(175.1)	—
Accrued unbilled revenues	42.3	—	—	42.3
Inventories	100.7	0.1	—	100.8
Recoverable fuel & natural gas costs	7.8	—	—	7.8
Prepayments & other current assets	34.4	8.0	(5.2)	37.2
Total current assets	279.9	177.7	(180.3)	277.3
Utility Plant				
Original cost	7,394.3	0.2	—	7,394.5
Less: accumulated depreciation & amortization	2,850.9	—	—	2,850.9
Net utility plant	4,543.4	0.2	—	4,543.6
Investments in consolidated subsidiaries	—	1,776.4	(1,776.4)	—
Notes receivable from consolidated subsidiaries	—	1,220.0	(1,220.0)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	30.3	0.4	—	30.7
Nonutility plant - net	1.6	200.9	—	202.5
Goodwill - net	205.0	—	—	205.0
Regulatory assets	351.8	14.8	—	366.6
Other assets	62.4	1.6	—	64.0
TOTAL ASSETS	$ 5,474.6	$ 3,392.0	$ (3,176.7)	$ 5,689.9

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 118.5	$ 6.7	$ —	$ 125.2
Intercompany payables	14.5	—	(14.5)	—
Payables to other Vectren companies	29.2	—	—	29.2
Accrued liabilities	162.6	19.5	(5.2)	176.9
Short-term borrowings	—	225.3	—	225.3
Intercompany short-term borrowings	153.1	7.5	(160.6)	—
Total current liabilities	477.9	259.0	(180.3)	556.6
Long-Term Debt				
Long-term debt	384.3	1,345.3	—	1,729.6
Long-term debt due to VUHI	1,220.0	—	(1,220.0)	—
Total long-term debt - net	1,604.3	1,345.3	(1,220.0)	1,729.6
Deferred Credits & Other Liabilities				
Deferred income taxes	459.4	23.7	—	483.1
Regulatory liabilities	937.6	1.1	—	938.7
Deferred credits & other liabilities	219.0	1.5	—	220.5
Total deferred credits & other liabilities	1,616.0	26.3	—	1,642.3
Common Shareholder's Equity				
Common stock (no par value)	892.2	879.2	(892.2)	879.2

Retained earnings	884.2	882.2	(884.2)	882.2
Total common shareholder's equity	1,776.4	1,761.4	(1,776.4)	1,761.4
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 5,474.6	$ 3,392.0	$ (3,176.7)	$ 5,689.9

Condensed Consolidating Balance Sheet as of December 31, 2017 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Assets				
Cash & cash equivalents	$ 8.2	$ 1.6	$ —	$ 9.8
Accounts receivable - less reserves	109.2	0.3	—	109.5
Intercompany receivables	—	227.5	(227.5)	—
Accrued unbilled revenues	123.7	—	—	123.7
Inventories	117.5	—	—	117.5
Recoverable fuel & natural gas costs	19.2	—	—	19.2
Prepayments & other current assets	28.9	12.6	(8.8)	32.7
Total current assets	406.7	242.0	(236.3)	412.4
Utility Plant				
Original cost	7,015.4	—	—	7,015.4
Less: accumulated depreciation & amortization	2,738.7	—	—	2,738.7
Net utility plant	4,276.7	—	—	4,276.7
Investments in consolidated subsidiaries	—	1,741.0	(1,741.0)	—
Notes receivable from consolidated subsidiaries	—	970.7	(970.7)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	26.3	0.4	—	26.7
Nonutility plant - net	1.6	197.0	—	198.6
Goodwill - net	205.0	—	—	205.0
Regulatory assets	298.7	15.3	—	314.0
Other assets	62.5	1.8	(0.1)	64.2
TOTAL ASSETS	$ 5,277.7	$ 3,168.2	$ (2,948.1)	$ 5,497.8

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
Current Liabilities				
Accounts payable	$ 179.4	$ 42.4	$ —	$ 221.8
Intercompany payables	8.3	—	(8.3)	—
Payables to other Vectren companies	25.2	8.1	—	33.3
Accrued liabilities	147.7	15.1	(8.8)	154.0
Short-term borrowings	—	179.5	—	179.5
Intercompany short-term borrowings	120.2	—	(120.2)	—
Current maturities of long-term debt	—	100.0	—	100.0
Current maturities of long-term debt due to VUHI	99.0	—	(99.0)	—
Total current liabilities	579.8	345.1	(236.3)	688.6
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	384.5	1,095.0	—	1,479.5
Long-term debt due to VUHI	970.7	—	(970.7)	—
Total long-term debt - net	1,355.2	1,095.0	(970.7)	1,479.5
Deferred Credits & Other Liabilities				
Deferred income taxes	455.3	2.2	—	457.5
Regulatory liabilities	936.1	1.1	—	937.2
Deferred credits & other liabilities	210.3	2.0	(0.1)	212.2

Total deferred credits & other liabilities	1,601.7	5.3	(0.1)	1,606.9
Common Shareholder's Equity				
Common stock (no par value)	890.7	877.5	(890.7)	877.5
Retained earnings	850.3	845.3	(850.3)	845.3
Total common shareholder's equity	1,741.0	1,722.8	(1,741.0)	1,722.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 5,277.7	$ 3,168.2	$ (2,948.1)	$ 5,497.8

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Condensed Consolidating Statement of Income for the three months ended September 30, 2018 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 122.1	$ —	$ —	$ 122.1
Electric utility	160.0	—	—	160.0
Other	—	11.8	(11.7)	0.1
Total operating revenues	282.1	11.8	(11.7)	282.2
OPERATING EXPENSES				
Cost of gas sold	24.5	—	—	24.5
Cost of fuel & purchased power	47.5	—	—	47.5
Other operating	95.1	—	(11.6)	83.5
Depreciation & amortization	56.3	7.1	—	63.4
Taxes other than income taxes	13.0	0.5	—	13.5
Total operating expenses	236.4	7.6	(11.6)	232.4
OPERATING INCOME	45.7	4.2	(0.1)	49.8
Other income - net	9.0	14.6	(14.4)	9.2
Interest expense	19.1	15.7	(14.5)	20.3
INCOME BEFORE INCOME TAXES	35.6	3.1	—	38.7
Income taxes	5.7	—	—	5.7
Equity in earnings of consolidated companies, net of tax	—	29.9	(29.9)	—
NET INCOME	$ 29.9	$ 33.0	$ (29.9)	$ 33.0

Condensed Consolidating Statement of Income for the three months ended September 30, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 120.4	$ —	$ —	$ 120.4
Electric utility	159.2	—	—	159.2
Other	—	11.4	(11.3)	0.1
Total operating revenues	279.6	11.4	(11.3)	279.7
OPERATING EXPENSES				
Cost of gas sold	23.9	—	—	23.9
Cost of fuel & purchased power	44.1	—	—	44.1
Other operating	93.2	—	(11.2)	82.0
Depreciation & amortization	52.5	6.5	—	59.0
Taxes other than income taxes	12.1	0.5	—	12.6
Total operating expenses	225.8	7.0	(11.2)	221.6
OPERATING INCOME	53.8	4.4	(0.1)	58.1
Other income - net	7.7	12.7	(12.3)	8.1
Interest expense	17.2	13.5	(12.4)	18.3
INCOME BEFORE INCOME TAXES	44.3	3.6	—	47.9
Income taxes	16.1	1.0	—	17.1
Equity in earnings of consolidated companies, net of tax	—	28.2	(28.2)	—

NET INCOME	$ 28.2	$ 30.8	$ (28.2)	$ 30.8

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Condensed Consolidating Statement of Income for the nine months ended September 30, 2018 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 600.7	$ —	$ —	$ 600.7
Electric utility	437.4	—	—	437.4
Other	—	35.3	(35.1)	0.2
Total operating revenues	1,038.1	35.3	(35.1)	1,038.3
OPERATING EXPENSES				
Cost of gas sold	211.4	—	—	211.4
Cost of fuel & purchased power	137.7	—	—	137.7
Other operating	300.2	—	(34.6)	265.6
Depreciation & amortization	165.3	20.9	0.1	186.3
Taxes other than income taxes	45.9	1.6	—	47.5
Total operating expenses	860.5	22.5	(34.5)	848.5
OPERATING INCOME	177.6	12.8	(0.6)	189.8
Other income - net	27.0	42.8	(41.9)	27.9
Interest expense	56.4	46.4	(42.5)	60.3
INCOME BEFORE INCOME TAXES	148.2	9.2	—	157.4
Income taxes	25.2	(0.6)	—	24.6
Equity in earnings of consolidated companies, net of tax	—	123.0	(123.0)	—
NET INCOME	$ 123.0	$ 132.8	$ (123.0)	$ 132.8

Condensed Consolidating Statement of Income for the nine months ended September 30, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations & Reclassifications	Consolidated
OPERATING REVENUES				
Gas utility	$ 557.2	$ —	$ —	$ 557.2
Electric utility	433.0	—	—	433.0
Other	—	34.2	(34.0)	0.2
Total operating revenues	990.2	34.2	(34.0)	990.4
OPERATING EXPENSES				
Cost of gas sold	174.0	—	—	174.0
Cost of fuel & purchased power	128.8	—	—	128.8
Other operating	283.8	—	(33.4)	250.4
Depreciation & amortization	154.9	19.3	0.1	174.3
Taxes other than income taxes	38.7	1.4	—	40.1
Total operating expenses	780.2	20.7	(33.3)	767.6
OPERATING INCOME	210.0	13.5	(0.7)	222.8
Other income - net	20.4	36.9	(35.9)	21.4
Interest expense	51.0	39.1	(36.6)	53.5
INCOME BEFORE INCOME TAXES	179.4	11.3	—	190.7
Income taxes	66.8	1.7	—	68.5
Equity in earnings of consolidated companies, net of tax	—	112.6	(112.6)	—
NET INCOME	$ 112.6	$ 122.2	$ (112.6)	$ 122.2

Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2018 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 298.3	$ 22.9	$ —	$ 321.2
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt - net of issuance costs	124.7	250.3	(125.7)	249.3
Additional capital contribution from parent	1.6	1.7	(1.6)	1.7
Requirements for:				
Dividends to parent	(89.2)	(96.0)	89.2	(96.0)
Retirement of long term debt	—	(100.0)	—	(100.0)
Net change in intercompany short-term borrowings	(66.1)	7.4	58.7	—
Net change in short-term borrowings	—	45.8	—	45.8
Net cash used in financing activities	(29.0)	109.2	20.6	100.8
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	89.2	(89.2)	—
Requirements for:				
Capital expenditures, excluding AFUDC equity	(389.2)	(35.6)	—	(424.8)
Consolidated subsidiary investments	—	(1.6)	1.6	—
Net change in long-term intercompany notes receivable	124.3	(250.0)	125.7	—
Net change in short-term intercompany notes receivable	(7.4)	66.1	(58.7)	—
Net cash used in investing activities	(272.3)	(131.9)	(20.6)	(424.8)
Net change in cash & cash equivalents	(3.0)	0.2	—	(2.8)
Cash & cash equivalents at beginning of period	8.2	1.6	—	9.8
Cash & cash equivalents at end of period	$ 5.2	$ 1.8	$ —	$ 7.0

Condensed Consolidating Statement of Cash Flows for the nine months ended September 30, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 293.8	$ 44.4	$ —	$ 338.2
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	24.7	99.4	(24.9)	99.2
Additional capital contribution from parent	44.6	44.6	(44.6)	44.6
Requirements for:				
Dividends to parent	(54.9)	(92.5)	54.9	(92.5)
Net change in intercompany short-term borrowings	44.4	(5.8)	(38.6)	—
Net change in short-term borrowings	—	17.3	—	17.3
Net cash used in financing activities	58.8	63.0	(53.2)	68.6
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	54.9	(54.9)	—
Other collections	2.8	—	—	2.8
Requirements for:				
Capital expenditures, excluding AFUDC equity	(363.3)	(48.4)	—	(411.7)

Consolidated subsidiary investments	—	(44.6)	44.6	—
Other costs	(2.4)	—	—	(2.4)
Changes in restricted cash	0.9	—	—	0.9
Net change in long-term intercompany notes receivable	—	(24.9)	24.9	—
Net change in short-term intercompany notes receivable	5.8	(44.4)	38.6	—
Net cash used in investing activities	(356.2)	(107.4)	53.2	(410.4)
Net change in cash & cash equivalents	(3.6)	—	—	(3.6)
Cash & cash equivalents at beginning of period	7.6	1.8	—	9.4
Cash & cash equivalents at end of period	$ 4.0	$ 1.8	$ —	$ 5.8

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5. 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 billed to customers, which totaled $5.4 million and $5.3 million in the three months ended September 30, 2018 and 2017, respectively, as a component of operating revenues. During the nine months ended September 30, 2018 and 2017, these taxes totaled $22.2 million and $20.2 million, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

6. Supplemental Cash Flow Information

As of September 30, 2018 and December 31, 2017, the Company had accruals related to utility and nonutility plant purchases totaling approximately $39.4 million and $27.5 million, respectively.

7. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of the Company's parent, provides underground pipeline construction and repair services. VISCO's customers include the Company's utilities and fees incurred by the Company totaled $40.9 million and $46.5 million for the three months ended September 30, 2018 and 2017, respectively, and for the nine months ended September 30, 2018 and 2017 totaled $105.2 million and $123.9 million, respectively. Amounts owed to VISCO at September 30, 2018 and December 31, 2017 are included in Payables to other Vectren companies in the Condensed Consolidated Balance Sheets.

Support Services & Purchases
The Company's parent provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. For the three months ended September 30, 2018 and 2017, the company received corporate allocations totaling $11.4 million and $16.4 million, respectively. For the nine months ended September 30, 2018 and 2017, the Company received corporate allocations totaling $40.7 million and $49.8 million, respectively.

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

Income Taxes
On December 22, 2017, the United States government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (“TCJA”). The TCJA makes broad and complex changes to the Internal Revenue Code (“IRC”), many of which were effective on January 1, 2018, including, but not limited to, (1) reducing the Federal corporate income tax rate from 35 percent to 21 percent, (2) eliminating the use of bonus depreciation for regulated utilities, while permitting full expensing of qualified property for non-regulated entities, (3) eliminating the domestic production activities deduction previously allowable under Section 199 of the IRC, (4) creating a new limitation on the deductibility of interest expense for non-regulated businesses, (5) eliminating the corporate Alternative Minimum Tax (“AMT”) and changing how existing AMT credits can be realized, (6) limiting the deductibility of certain executive compensation, (7) restricting the deductibility of entertainment and lobbying-related expenses, (8) requiring regulated

entities to employ the average rate assumption method (“ARAM”) to refund excess deferred taxes created by the rate change to their customers, and (9) changing the rules regarding taxability of contributions made by government or civic groups.

The Company's gas and electric utilities currently recover corporate income tax expense in approved rates charged to customers. The IURC and the PUCO both issued orders which initiated proceedings to investigate the impact of the TCJA on utility companies and customers within each state. In addition, both Commissions have ordered each utility to establish regulatory assets and liabilities to record all estimated impacts of tax reform starting January 1, 2018. The Company is complying with both orders. As of September 30, 2018, the Company has established $35.7 million in liabilities associated with the rate impacts of tax reform, including $5.2 million in Regulatory Liabilities and $30.5 million in Accrued Liabilities.

In Indiana, an order was issued by the IURC on February 16, 2018, outlining the process the utility companies are to follow. In accordance with the order, the Company filed March 26, 2018 for proposed changes to its rates and charges to consider the impact of the lower corporate federal income tax rate. The IURC approved an initial reduction to the Company's current rates and charges, effective June 1, 2018, to capture the immediate impact of the lower corporate federal income tax rate. Also, on June 1, 2018, a settlement agreement, reached between the Company, the Indiana Office of the Utility Consumer Counselor (OUCC), and a coalition of industrial customers, was filed with the IURC. The settlement agreement resolves all the proposed changes to rates as a result of the TCJA, specifically regarding the refund of excess deferred taxes and the refund of the regulatory liabilities established starting January 1, 2018. The IURC issued an order on August 29, 2018 approving the settlement agreement. The refund of excess deferred taxes and regulatory liabilities will commence in November 2018 for the Company's Indiana electric customers and in January 2019 for the Company's Indiana gas customers.

In Ohio, on October 24, 2018, the PUCO issued an Order requiring all utilities to file by January 1, 2019 for a request to adjust rates to reflect the impact of the TCJA. In compliance with this Order and consistent with VEDO comments submitted within this proceeding, VEDO will make a filing later this year to address its proposal for the refund of TCJA impacts, with a request to consolidate the proceeding with its pending base rate case filed on March 30, 2018.

8. Financing Activities

SIGECO Variable Rate Tax-Exempt Bonds
On March 1, 2018 and May 1, 2018, the Company, through SIGECO, executed first and second amendments to a Bond Purchase and Covenants Agreement originally signed in September 2017. These amendments provided SIGECO the ability to remarket bonds that were callable from current bondholders on those dates. Pursuant to these amendments, lenders purchased the following SIGECO bonds on March 1 and May 1, respectively:

- 2013 Series A Notes with a principal of $22.2 million and final maturity date of March 1, 2038; and
- 2013 Series B Notes with a principal of $39.6 million and final maturity date of May 1, 2043.

Prior to the call, the 2013 Series A Notes had an interest rate of 4.0% and the 2013 Series B Notes had an interest rate of 4.05%. The bonds converted to a variable rate based on the one month LIBOR through May 1, 2023.

The Company has now remarketed $152 million of tax exempt bonds through the Bonds Purchase and Covenants Agreement, which is the agreement's full capacity. Bonds remarketed through the Bond Purchase and Covenants Agreement in 2017 were:

- 2013 Series C Notes with a principal of $4.6 million and final maturity date of January 1, 2022;
- 2013 Series D Notes with a principal of $22.5 million and final maturity date of March 1, 2024;
- 2013 Series E Notes with a principal of $22.0 million and final maturity date of May 1, 2037; and
- 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025.

These bonds also have a variable interest rate based on the one month LIBOR through May 1, 2023.

The Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the variability in interest rates on the 2013 Series A, B, and E Notes through final maturity dates. The swaps contain customary terms and conditions and generally provide offset for changes in the one month LIBOR rate. Other interest rate variability that may arise through the Bond Purchase and Covenants Agreement, such as variability caused by changes in tax law or SIGECO's credit rating, among others, may result in an actual interest rate above or below the anticipated fixed rate. Regulatory orders require SIGECO to include the impact of its interest rate risk management activities, such as gains and losses arising from these swaps, in its cost of capital utilized in rate cases and other periodic filings.

Utility Holdings Term Loan

On July 30, 2018, Utility Holdings executed a term loan agreement and closed a two-year term loan with two banking partners. The term loan agreement provides for a $250 million draw at closing and $50 million on or prior to December 31, 2018. Proceeds from the term loan have been utilized to pay a $100 million August 1, 2018, debt maturity and for general utility

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purposes. The term loan’s interest rate is currently priced at one month LIBOR, plus a credit spread, which is subject to change based on changes in Utility Holdings’ credit rating. A change in credit rating would add approximately 10 basis points, per rating notch, to the existing rate. In addition, the term loan contains a provision that should Utility Holdings or any of its subsidiaries execute certain capital market transactions, and subject to certain other conditions, the outstanding balance is subject to mandatory prepayment. The term loan is jointly and severally guaranteed by Utility Holdings' wholly-owned operating companies, SIGECO, Indiana Gas, and VEDO.

Utility Holdings Borrowing Arrangements
The Merger would constitute a “Change of Control” under the note agreements pursuant to which Senior Notes issued by Utility Holdings in an aggregate principal amount of $1.025 billion were issued. While the Merger would not result in an event of default under such note agreements, upon the consummation of the Merger the issuer would be required to offer to repurchase these notes at 100% of the principal amount thereof plus accrued interest.

The Merger will represent an event of default pursuant to Utility Holdings' short-term credit facility, and Utility Holdings is in process of seeking a waiver from the facility bank group of this event of default. If a waiver is not obtained, upon closing of the merger, CenterPoint will fund the obligations associated with the credit facility.

9. Commitments & Contingencies

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

Letters of Credit
The Company from time to time, through its subsidiaries, issues letters of credit that support consolidated operations. At September 30, 2018, letters of credit outstanding total $8.6 million.

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

Litigation Related to the Merger
As of November 6, 2018, seven purported Vectren shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in Vectren's proxy statement in connection with the merger. These cases are captioned Kuebler v. Vectren Corp., et al., Case No. 3:18-cv-00113-RLY-MPB (S.D. Ind.) (the “Kuebler Action”), Danigelis v. Vectren Corp., et al., Case No. 3:18-cv-00114-RLY-MPB (S.D. Ind.) (the “Danigelis Action”), Scarantino v. Vectren Corp., et al., Case No. 3:18-cv-00115-RLY-MPB (S.D. Ind.) (the “Scarantino Action”), Stein v. Vectren Corp., et al., Case No. 3:18-cv-00117-RLY-MPB (S.D. Ind.) (the “Stein Action”), Nisenshal v. Vectren Corp., et al., Case No. 3:18-cv-00121-RLY-MPB (S.D. Ind.) (the “Nisenshal Action”), VonSalzen v. Vectren Corp., et al., Case No. 3:18-cv-00122-RLY-MPB (S.D. Ind.) (the “VonSalzen Action”), and Kent v. Vectren Corp., et al., Case No. 1:18-cv-02263-SEB-TAB (S.D. Ind.) (the “Kent Action,” referred to together with the preceding actions, as the "Actions"). The Kuebler Action, the Danigelis Action, the Scarantino Action, the Nisenshal Action, and the Kent

Action are asserted on behalf of putative classes of Vectren shareholders, while the Stein Action and the VonSalzen Action are brought only on behalf of their respective named plaintiffs.

The actions allege violations of Sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9 promulgated thereunder based on various alleged omissions of material information from this proxy statement. The Kuebler Action, the Danigelis Action, the Stein Action, and the Nisenshal Action name as defendants Vectren and each of its directors, individually, and seek to enjoin the merger (or, in the alternative, rescission or an award of rescissory damages in the event the Merger is completed), damages, and an award of costs and attorneys' and expert fees. The Scarantino Action and Kent Action also name as defendants Vectren and each of its directors, individually, and seek to enjoin the Merger (or, in the alternative, rescission or an award of rescissory damages in the event the merger is completed), to compel Vectren's directors to issue a revised proxy statement, a declaration that the defendants violated Sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9 promulgated thereunder, and an award of costs and attorneys' and expert fees, and damages. The VonSalzen Action also names as defendants Vectren and each of its directors, individually, and seeks to enjoin the Merger (or, in the alternative, rescission or an award of rescissory damages in the event the Merger is completed), a declaration that the proxy statement is materially false or misleading, to compel Vectren's directors to account for damages, profits, and any special benefits obtained, and an award of costs and attorneys' and expert fees, and damages.

On July 10, 2018, the plaintiffs in the Kuebler Action and in the Danigelis Action filed motions for preliminary injunctions seeking to enjoin Vectren from consummating the Merger. On August 10, 2018, the court consolidated the actions and appointed a group as interim lead plaintiff. On August 22, 2018, the court denied interim lead plaintiffs' preliminary injunction, which sought to halt the Vectren shareholder vote on the Vectren Merger.

Vectren and the Vectren director defendants filed a motion to dismiss on August 15, 2018. On September 4, 2018, the court entered the parties' stipulation that the interim lead plaintiff group is under no obligation to oppose or otherwise respond to the motion to dismiss. Instead, under the stipulation, the lead plaintiff shall file a consolidated amended complaint or designate an operative complaint within thirty (30) days of the entry appointing lead plaintiff and lead counsel, and once the lead plaintiff files a consolidated amended complaint or designates an operative complaint, the case will proceed, as it ordinarily would, under the Federal Rules of Civil Procedure and the Local Rules for the Southern District of Indiana. On September 4, 2018, interim plaintiffs filed a motion for appointment as lead plaintiffs and approval of their selection of counsel as lead counsel. On September 28, 2018, the court granted the interim plaintiffs' motion for appointment and ordered lead plaintiffs to file a consolidated amended complaint or designate an operative complaint within thirty (30) days of the entry in accordance with the court's September 4, 2018 entry of the parties' stipulation.

On October 29, 2018, lead plaintiffs filed an amended consolidated complaint asserting claims under Sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9 promulgated thereunder based on various alleged omissions of material information from the final proxy statement. Plaintiffs seek compensatory and/or rescissory damages and an award of costs and attorneys' and expert fees. On November 8, 2018, the court entered the parties' stipulation for the filing of a motion, answer, or other response to plaintiffs' amended complaint, by which defendants shall have filed their motion, answer, or other response by December 7, 2018. Plaintiffs shall file response to any motion to dismiss by January 11, 2018 and defendants shall reply by February 8, 2018.

Vectren believes that these complaints are without merit and cannot predict the outcome of or estimate the possible loss or range of loss from these matters.

10. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

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

Indiana Senate Bill 251 (Senate Bill 251) provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the IURC, through a base rate case or other proceeding, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require, among other things, requests for recovery including a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, except for the rate of return on equity, which remains fixed at the rate determined in the Company's last base rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred for future recovery in the utility's next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of not more than two percent.

Ohio House Bill 95 (House Bill 95) permits a natural gas utility to apply for recovery of much of its capital expenditure program. This legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post-in-service carrying costs until recovery is approved by the PUCO.

Requests for Recovery under Indiana Regulatory Mechanisms
In August 2014, the IURC issued an Order approving the Company's seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the statutes, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company's next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company's proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

Since this August 2014 Order, the Company has received eight semi-annual orders which approved the inclusion in rates of approximately $563 million of approved capital investments through December 31, 2017.

On June 20, 2018, the Indiana Supreme Court issued an opinion (Opinion) in an appeal of an IURC order under Indiana Senate Bill 560 for a utility unrelated to the Company. In this Opinion, the Court determined that one of the programs within that utility's approved plan did not constitute a "designated" capital improvement because the individual projects within the program were not specifically set forth in the approved seven-year plan, and, instead were designated later based on subsequently developed information. The IURC had previously approved the program and thereby allowed individual projects under the program to be designated in the future and that action was then appealed by intervenors in the TDSIC proceeding. The Company has evaluated the opinion's potential application to the Company's Plan. The Company believes the ruling is limited to prospective projects that have not previously been designated and approved in final orders issued in the TDSIC process. The Company has determined that TDSIC projects in the service replacement plan category do not constitute a designated capital improvement, and therefore as a result of the Opinion is removing the associated projects that were not previously the subject of final orders, totaling approximately $40 million over the remaining term of the plan. Such projects are still eligible for recovery in a future base rate case. The Company does not expect a resulting material impact to results of operations or cash flow from operations.

On October 1, 2018, the Company submitted its ninth semi-annual filing, seeking approval of the recovery in rates of investments made through June 30, 2018, and updates to the approved seven-year capital investment plan. The updated plan reflects capital expenditures of approximately $955 million. The Company expects an order in this proceeding in early 2019.

At September 30, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $92.3 million and $78.0 million, respectively.

In December 2016, PHMSA issued interim final rules related to integrity management for storage operations. Efforts are underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led task force. On August 3, 2017, the Company filed for authority to recover the associated costs using the mechanism allowed under Senate Bill 251. Approximately $15 million of operating expenses and $17 million of capital investments will be included in the plan over a four-year period beginning in 2018. The Company received the IURC Order approving the request for recovery on

December 28, 2017. The Company does not have company-owned storage operations in Ohio.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In the Company's base rate case, it requested extension to include investments made starting 2018 through completion of the program, currently estimated at 2023. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $353.1 million as of September 30, 2018, of which $321.1 million has been approved for recovery under the DRR through December 31, 2017. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $36.5 million and $31.2 million at September 30, 2018 and December 31, 2017, respectively.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. The Company has requested recovery of these deferrals through December 31, 2017 in its rate case, along with a mechanism to recover future Ohio House Bill 95 deferrals. At September 30, 2018 and December 31, 2017, the Company has regulatory assets totaling $90.1 million and $66.1 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. On May 1, 2018, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Vectren Ohio Gas Rate Case
On March 30, 2018, the Company filed with the PUCO a request for a $34 million increase in its base rates and charges for VEDO’s distribution business in its 17 county service area in west-central Ohio. The requested increase includes the benefit of the TCJA, which decreased the corporate rate from 35 percent to 21 percent. The filing is necessary to extend the DRR mechanism beyond 2017 through completion of the accelerated replacement program, and to recover the costs of capital investments made over the past ten years, much of which has been deferred as part of the Company’s capital expenditure program under Ohio House Bill 95. The filing also addresses the recovery of the current Ohio House Bill 95 regulatory asset balance, and a proposed mechanism to recover future Ohio House Bill 95 deferrals.

On October 1, 2018, the PUCO staff filed its report of its audit in this proceeding, including recommendations for a revenue increase between $12 million and $16 million. Much of the reduction relates to periodic recovery mechanism versus base rate method of cost recovery, a reduction to the requested ROE, and a reduction to certain operating expenses. Staff was supportive of the continuation of the DRR and the expansion of straight-fixed-variable rate design to small commercial customers. The Company and other parties filed objections to the Staff report adjustments on October 31, 2018, and the Company will file supplemental testimony in early November 2018, continuing to support its filed position. The Commission has set the procedural schedule in this proceeding, with a prehearing conference scheduled for November 15, 2018, followed by three field hearings to occur in November and an evidentiary hearing to begin on December 4, 2018. The Company expects an order by early 2019.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
In March 2016, PHMSA published a notice of proposed rulemaking (NOPR) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company continues to evaluate the impact these proposed rules will have on its integrity management programs and transmission and distribution systems. Progress on finalizing the rule continues to work through the administrative process. The rule is expected to be finalized in 2019 and the Company believes the costs to comply with the new rules would be considered federally mandated and therefore should be recoverable under Senate Bill 251 in Indiana and eligible for deferral under House Bill 95 in Ohio.

11. Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560
The provisions of Senate Bill 560, as described in Note 10 for gas projects, are the same for qualifying electric projects. On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company's network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers.

On September 20, 2017, the IURC issued an Order approving the Company's electric system modification as reflected in the settlement agreement reached between the Company, the OUCC, and a coalition of industrial customers. The settlement agreement includes defined annual caps on recoverable capital investments, with the total approved plan set at $446.5 million. The settlement agreement also addresses how the eligible costs would be recoverable in rates, with a cap on the residential and small general service fixed monthly charge per customer in each semi-annual filing. The remaining costs to residential and small general service customers would be recovered via a volumetric energy charge. The settlement agreement removed advanced metering infrastructure (AMI or digital meters) from the plan. However, deferral of the costs for AMI was agreed upon in the settlement whereby the company can move forward with deployment in the near-term. The request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which is expected to be filed by the end of 2023. In that proceeding, settling parties have agreed not to oppose inclusion of the AMI project in rate base.

On December 20, 2017, the IURC issued an Order approving the initial rates necessary to begin cash recovery of 80 percent of the revenue requirement, inclusive of return, with the remaining 20 percent deferred for recovery in the utility's next general rate case. These initial rates captured approved investments made through April 30, 2017.

On May 23, 2018, the IURC issued an order (May 2018 order) for the second semi-annual filing approving the inclusion in rates of investments made from May 2017 through October 2017. Through the May 2018 order, approximately $31 million of the approved capital investment plan has been incurred and approved for recovery.

On August 1, 2018, the Company submitted its third semi-annual filing, seeking approval of the recovery in rates of approximately $58 million through April 2018.

On June 20, 2018, the Indiana Supreme Court issued an opinion (Opinion) in an appeal of an IURC order under Indiana Senate Bill 560 for a utility unrelated to the Company. In this Opinion, the Court determined that one of the programs within that utility's approved plan did not constitute a "designated" capital improvement because the individual projects within the program were not specifically set forth in the approved seven-year plan, and, instead were designated later based on subsequently developed information. The IURC had previously approved the program and thereby allowed individual projects under the program to be designated in the future and that action was then appealed by intervenors in the TDSIC proceeding. The Company has evaluated the opinion’s potential application of the Company’s Plan. The Company believes the ruling is limited to prospective projects that have not previously been designated and approved in final orders issued in the TDSIC process. The Company has determined that TDSIC projects in the pole replacement plan category that weren't previously the subject of final orders, totaling approximately $35 million, do not constitute a designated capital improvement eligible for recovery given this Opinion. As the Company has the ability under the electric plan to substitute projects with other approved projects within defined annual cost caps, the Company does not expect this Opinion to impact the total amount of the approved plan, and therefore does not expect a resulting material impact to results of operations or cash flow from operations. The Company removed the projects from the plan in accordance with the Opinion when it filed its third semi-annual TDSIC proceeding on August 1, 2018.

As of September 30, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $5.1 million and $4.3 million, respectively.

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. 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.

As of 2017, the Company has completed investments of $30 million on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of September 30, 2018, the Company has approximately $17.0 million deferred related to depreciation and operating expenses, and $6.1 million deferred related to post-in-service carrying costs. MATS compliance was required beginning April 16, 2015 and the Company continues to operate in full compliance with the MATS rule.

On February 20, 2018, as part of the electric generation transition plan case discussed below, the Company filed a request to commence recovery, under Senate Bill 251, of its already approved investments associated with the MATS and NOV Compliance Projects, including recovery of the authorized deferred balance. As proposed, recovery would reflect 80 percent of the authorized costs, including a return, recovery of depreciation and incremental operating expenses, and recovery of the prior deferred balance over a proposed period of 15 years. The remaining 20 percent will be deferred until the Company’s next base rate proceeding. The Company expects an order in the first half of 2019.

SIGECO Electric Demand Side Management (DSM) Program Filing
On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, customers representing most of the eligible load have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also requires the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company’s 2016-2017 energy efficiency plan. The Order provided for cost recovery of program and administrative expenses and included performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that would have limited recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling followed other IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company appealed this lost margin recovery restriction based on the Company’s commitment to promote and drive participation in its energy efficiency programs.

On March 7, 2017, the Indiana Court of Appeals reversed the IURC finding on the Company's 2016-2017 energy efficiency plan that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring it to review the utility's originally submitted DSM proposal and either approve or reject it as a whole, including the proposed lost margin recovery. The case was remanded to the IURC for further proceedings. On June 13, 2017, the Company filed additional testimony supporting the plan. In response to the proposals to cap lost margin recovery, the Company filed supplemental testimony that supported lost margin recovery based on the average measure life of the plan, estimated at nine years, on 90 percent of the direct energy savings attributed to the programs. Testimony of intervening parties was filed on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 20, 2017, the Commission issued an order approving the DSM Plan for 2016-2017 including the recovery of lost margins consistent with the Company's proposal. On January 22, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. Briefing is now complete. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission's order, the Company expects to prevail in this appeal.

On April 10, 2017, the Company submitted its request for approval to the IURC of its Energy Efficiency Plan for calendar years 2018 through 2020. Consistent with prior filings, this filing included a request for continued cost recovery of program and administrative expenses, including performance incentives for reaching energy savings goals and continued recovery of lost margins consistent with the modified proposal in the 2016-2017 plan. Filed testimony of intervening parties was received on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 28, 2017, the Commission issued an order approving the 2018 through 2020 Plan, inclusive of recovery of lost margins consistent with the Order issued on December 20, 2017. On January 26, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. Briefing is now complete. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission's order, the Company expects to prevail in this appeal.

For the nine months ended September 30, 2018 and 2017, the Company recognized electric utility revenue of $9.1 million and
$8.7 million, respectively, associated with lost margin recovery approved by the Commission.

FERC Return on Equity (ROE) Complaints
On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against the MISO and various MISO transmission owners, including SIGECO (first complaint case). The joint parties sought to reduce the 12.38 percent base ROE used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent covering the refund period from November 12, 2013 through February 11, 2015 (first refund period). On September 28, 2016, the FERC issued a final order authorizing a 10.32 percent base ROE for the first refund period and prospectively through the date of the order in a second complaint case as detailed below.

A second customer complaint case was filed on February 11, 2015 covering the refund period from February 12, 2015 through May 11, 2016 (second refund period). An initial decision from the FERC administrative law judge on June 30, 2016, authorized a base ROE of 9.70 percent for the second refund period. The FERC was expected to rule on the proposed order in the second complaint case in 2017, which would authorize a base ROE for this period and prospectively from the date of the order. The timing of such action is uncertain.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The adder is applied retroactively from January 6, 2015 through May 11, 2016 and prospectively from the September 28, 2016 order in the first complaint case.

The Company has reflected these results in its financial statements. As of September 30, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.9 million at September 30, 2018.

On April 14, 2017, the U.S. Court of Appeals for the District of Columbia circuit vacated the FERC Opinion in a prior case that established a new methodology for calculating ROE. This methodology was utilized in the final order in the Company's first complaint case, and the initial decision in the Company's second complaint case. The Appeals Court stated that FERC did not prove the existing ROE was not just and reasonable, failed to provide any reasoned basis for their selected ROE, and remanded to the FERC for further justification of its ROE calculation. On October 16, 2018, FERC issued an order in the case establishing a modified ROE calculation framework. The Company is evaluating the order to determine impacts, if any, on the Company's complaint cases, but does not expect any impact to be material.

Electric Generation Transition Plan

As required by Indiana regulation, the Company filed its 2016 Integrated Resource Plan (IRP) with the IURC on December 16, 2016. The State requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty-year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio. After submission, parties to the IRP provided comments on the plan. While the IURC does not approve or reject the IRP, the process involves the issuance of a staff report that provides comments on the IRP. The final report was issued on November 2, 2017. The Company has taken the comments provided in the report into consideration in its generation transition plan.

The Company’s IRP considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. Consistent with the recommendations presented in the Company’s IRP and as a direct result of significant environmental investments required to comply with current regulations, the Company plans to retire a significant portion of its generating fleet by the end of 2023. On February 20, 2018, the Company filed a petition seeking authorization from the IURC to construct a new 800-900 MW natural gas combined cycle generating facility to replace this capacity at an approximate cost of $900 million, which includes the cost of a new natural gas pipeline to serve the plant. The Company is requesting a certificate of public convenience and necessity (CPCN) authorizing construction timelines and costs of new generation resources, as well as necessary unit retrofits, to implement the generation transition plan. In that filing, the Company seeks approval of its generation transition plan, including the authority to defer the cost of new generation, including the ability to accrue AFUDC and defer depreciation until the facility is placed in base rates.

As a part of this same proceeding, the Company seeks recovery under Senate Bill 251 of costs to be incurred for environmental investments to be made at its F.B. Culley generating plant to comply with Effluent Limitation Guidelines and Coal Combustion Residuals rules. The F.B. Culley investments, estimated to be approximately $95 million, will begin in 2019 and will allow the F.B. Culley Unit 3 generating facility to comply with environmental requirements and continue to provide generating capacity to the Company’s electric customers. Under Senate Bill 251, the Company is seeking recovery of 80 percent of the approved costs, including a return, using a tracking mechanism, with the remaining 20 percent of the costs deferred for recovery in the Company’s next base rate proceeding.

On August 10, 2018, most of the intervening parties filed direct testimony opposing the Company’s proposed generation investments, and an evidentiary hearing has been completed. The Company continues to support the proposed investments and expects an order from the Commission in the CPCN proceeding in the first half of 2019.

On August 30, 2017, the IURC issued an Order approving the Company’s request to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company's (IRP) submitted in December 2016, allow the Company to add approximately 4 MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. The approved cost of the projects cannot exceed the approximate $16 million estimate submitted by the Company, without seeking further Commission approval.

On February 20, 2018, the Company announced it is finalizing details to install an additional 50 MW of universal solar energy, consistent with its IRP. On May 4, 2018, the Company filed a petition with the IURC requesting a CPCN authorizing construction and authority to recover costs associated with the project pursuant to Senate Bill 29. On September 5, 2018, the intervening parties filed testimony opposing the investment, and on September 18, 2018 the Company filed its rebuttal testimony in response. On October 10, 2018, a settlement agreement between all but one of the intervening parties and Vectren was filed. The settlement agreement provides for a rate recovery approach whereby the energy produced by the solar farm would be recovered via a fixed rate over the life of the investment. The settlement is now pending before the Commission, with an evidentiary hearing scheduled for November 19, 2018. The Company would expect an order in the first half of 2019.

Other Generation Developments

On September 21, 2017, the Company and Alcoa agreed to continue the joint ownership and operation of Warrick Unit 4 through 2023. This aligns with the Company's long-term electric generation transition plan, and the expected exit at the end of 2023 is consistent with the IRP which reflects having completed all planned unit retirements and bringing new resources online by that date.

On September 28, 2017, the Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR) to the FERC for consideration of payment to certain resources that have on-site fuel and demonstrate a form of resilience. On January 8, 2018, after receiving a majority of comments from the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) opposing the relief requested by the DOE, the FERC declined to issue the NOPR and, instead, initiated a proceeding (FERC Docket No. AD18-7) to further explore the current planning that RTOs and ISOs are undertaking to ensure resiliency, as well as other regional aspects to determine the need for action of the type recommended by the DOE. This proceeding is still pending before the FERC. In the interim, a draft memorandum that was purportedly prepared by the DOE was made public on May 31, 2018. The draft memorandum calls for immediate action by the President of the United States to exercise authority under the Defense Production Act and Federal Power Act to provide for temporary subsidy payments to coal and nuclear resources while a two year study is performed to identify Defense Critical Electric Infrastructure (DCEI). The draft memorandum expands upon the original resiliency concerns expressed in the DOE's September 28, 2017 submission.
Following the publication of the draft DOE memorandum, the President publicly called for immediate action by the DOE. To date, the DOE has not publicly acted, including finalizing the draft memorandum and indicating facilities that would be eligible for these temporary subsidy payments or how they would be funded. At this time, the Company does not believe this activity will have any impact on its pending request for authorization from the IURC to construct a combined cycle gas turbine to serve the requirements of the Company’s electric utility system. Absent further information, the impact to electric customers and power generator owners is unknown.

12. Environmental & Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report. Since that time, the Company continues to develop strategies that focus on environmental, social, and governance (ESG) factors that contribute to the long-term growth of a sustainable business model. The sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by the Company's Corporate Responsibility and Sustainability Committee, as well as vetted with the Company's Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s current sustainability report, at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

In furtherance of the Company’s commitment to a sustainable business model, and as detailed further below, the Company is transitioning its electric generation portfolio from nearly total reliance on baseload coal to a fully diversified and balanced portfolio of fuels that will provide long term electric supply needs in a safe and reliable manner while dramatically lowering emissions of carbon and the carbon intensity of its electric generating fleet. If authorized by the Commission, by 2024 the Company plans to construct a new natural gas combined cycle generating facility to replace four coal-fired units totaling over 700 MWs which, when combined with its planned 54 MWs of new renewable generation, will achieve a 60 percent reduction in carbon emissions from 2005 levels and reduce carbon intensity to 980 lbs CO_2 / MMBTU and position the Company to comply with future carbon emission reduction requirements. In addition to diversification of its fuel portfolio, the Company is also seeking authorization to significantly upgrade wastewater treatment for its remaining coal-fired unit and exploring opportunities to continue to recycle ash from its coal ash ponds. This generation diversification strategy aligns with the Company’s ongoing investments in new electric infrastructure through the approved $446.5 million grid modernization program, and is set forth in more detail in the Company’s 2017 corporate sustainability report.

Further, as part of its commitment to a culture of compliance excellence and continuous improvement, the Company continues to enhance its Safety Management System (SMS) which was implemented several years ago. The risk analysis and process review provides valuable input into the assessment process used to drive the ongoing infrastructure improvement plans being executed by the Company’s gas and electric utilities.

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), and mercury, among others.
Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August 2017, the EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. On July 17, 2018, EPA released its final CCR rule phase I reconsideration which extends for two years, from October 31, 2018 to October 31, 2020, the deadline for ceasing placement of ash in ponds that exceed groundwater protections standards or fails to meet location restrictions. The Company does not anticipate the reconsideration to change its current plans for pond closure as announced in its generation transition plan, since closure dates were not dependent upon the original October 2018 compliance date. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect. On August 21, 2018, the U.S. Court of Appeals for the D.C. Circuit issued an opinion in the underlying judicial review litigation, agreeing largely with the environmental challengers by vacating and remanding provisions of the 2015 rule that allowed unlined ash ponds to receive coal ash until a leak is detected and exempted inactive “legacy” impoundments. This decision effectively undercuts further attempts by EPA to make the rule less stringent on reconsideration.

Under the existing CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility. In March 2018, the Company posted to its public website a first report of preliminary groundwater monitoring data in accordance with the requirements of the CCR rule. This data preliminarily suggests potential groundwater impacts very close to the Company's ash impoundments, and further analysis is ongoing; however, at this time the Company does not believe that there are any impacts to public or private drinking water sources. The CCR rule requires that companies complete location restriction determinations by October 18, 2018. The Company has completed its evaluation under the rule and determined that one F.B. Culley pond and one A.B. Brown pond fail the aquifer placement location restriction requiring that ash cannot be disposed within five feet of the uppermost groundwater aquifer. The Company will be required to cease disposal and commence closure of the ponds by October 31, 2020. The Company plans to seek the extensions available under the CCR rule that would allow the Company to continue to use the ponds through completion of the generation transition plans by December 31, 2023.

Since 2015, the Company continues to refine site specific estimates and now estimates the costs to be in the range of $45 million to $135 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate complete removal under the assumption of beneficial reuse of the ash at A. B. Brown, as well as implications of the Company's generation transition plan. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash, either from a technological or economical perspective, could result in estimated costs in excess of the current range.

As of September 30, 2018, the Company has recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

On July 20, 2018, the Company filed a Complaint for Damages and Declaratory Relief against its insurers seeking reimbursement of defense, investigation, and pond closure costs incurred to comply with the CCR rule. The Company intends to apply any net proceeds from this litigation to offset costs that have been and will be deferred for future recovery from customers.

Effluent Limitation Guidelines (ELG)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. In September 2015, the EPA finalized revisions to the existing steam electric ELG setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELG will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELG work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company's IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by IDEM provided the Company notifies IDEM of its intent to retire the unit within 30 days of the receipt of the order in the CPCN proceeding. For the F.B.

Culley 3 plant, the Company requested a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by IDEM and finalized in the permit renewal. Discussion of these environmental investments at the F.B. Culley 3 plant is included in the generation transition plan in Note 11.

On April 13, 2017, as part of the Administration's regulatory reform initiative, which is focused on the number and nature of regulations, the EPA granted petitions to reconsider the ELG rule, and indicated it would stay the current implementation deadlines in the rule during the pendency of the reconsideration. On September 13, 2017, EPA finalized a rule postponing certain interim compliance dates by two years, but did not postpone the final compliance deadline of December 31, 2023. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not anticipate immediate impacts from the EPA's two-year extension of preliminary implementation deadlines due to the longer compliance time frames granted by IDEM, and will continue to work with IDEM to evaluate further implementation plans. Moreover, the Company believes the two year extension of the ELG preliminary implementation deadlines and reconsideration process does not impact its generation transition plan as modeled in the IRP because the final compliance deadline of December 31, 2023 is still in place and enhanced wastewater treatment for scrubber discharge water will still be required by a reconsidered ELG rule even if the EPA revises stringency levels.

Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires generating facilities use the "best technology available" (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires that IDEM conduct a case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company's facilities. On July 23, 2018, the U.S. Court of Appeals for the Second Circuit upheld the final rule on judicial review. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level within the range of 65 to 70 ppb. On October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. In November 2017, EPA finalized its designations of Vanderburgh, Posey, and Warrick counties as being in attainment with the current 70 ppb standard.

One Hour SO2 NAAQS

On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between IDEM and the EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO2 NAAQS. Identified on the list was Posey County, Indiana, where the Company's A.B. Brown Generating Station is located. While the Company is in compliance with all applicable SO2 limits in its permits, the Company reached an agreement with IDEM on voluntary measures the Company was able to implement without significant incremental costs to ensure Posey County remains in attainment with the 2010 One Hour SO2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Climate Change and Carbon Strategy

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which required a 32 percent reduction in carbon emissions from 2005 levels. This would result in a final emission rate goal for Indiana of 1,242 lb CO2/MWh to be achieved by 2030 and implemented through a state implementation plan. The final rule was published in the

Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA's reconsideration of the CPP rule, which was granted on April 28, 2017. Moreover, as indicated above, in October 2017, EPA published its proposal to repeal the CPP. Comments to the repeal proposal were due in April 2018. EPA's repeal proposal was quickly followed by an advanced notice of proposed rulemaking intended to solicit public comments on issues related to formulating a CPP replacement rule, which were similarly due in April 2018.

On August 31, 2018, EPA published its proposed CPP replacement rule, the Affordable Clean Energy (ACE) rule, which if finalized, would require that each state set unit by unit heat rate performance standards, considering such factors as remaining useful life. Under the ACE rule, a state would have three years to finalize its program and the EPA would have 18 months to approve, making compliance likely in 2023-2024. Comments to the ACE proposal were due October 31, 2018. Vectren filed comments which largely support EPA's ACE proposal.

Impact of Legislative Actions & Other Initiatives

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. However, Vectren's generation transition plan, as set forth in its electric generation and compliance filing, will achieve 60 percent reductions in 2005 GHG emission levels by 2025, positioning the Company to comply with future regulatory or legislative actions with respect to mandatory GHG reductions.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. The Administration has indicated it intends to withdraw the United States' participation; however, the Agreement provides that parties cannot petition to withdraw until November 2019. Since 2005 through 2017, the Company has achieved reduced emissions of CO2 by an average of 35 percent (on a tonnage basis), and will increase that total to 60 percent at the conclusion of its generation transition plan, well above the 32 percent reduction that would be required under the CPP. While the litigation and the EPA's reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.7 million ($23.9 million at Indiana Gas and $20.8 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.8 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of September 30, 2018 and December 31, 2017, approximately $2.8 million and $2.5 million, respectively of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

13. Fair Value Measurements

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

	September 30, 2018		December 31, 2017	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,729.6	$1,799.1	$1,579.5	$1,715.2
Short-term borrowings	225.3	225.3	179.5	179.5
Cash & cash equivalents	7.0	7.0	9.8	9.8
Natural gas purchase instrument assets (1)	0.1	0.1	0.5	0.5
Natural gas purchase instrument liabilities (2)	14.5	14.5	4.5	4.5
Interest rate swap assets (3)	3.3	3.3	—	—
Interest rate swap liabilities (4)	—	—	1.4	1.4

(1) Presented in "Prepayments & other current assets" for current and "Other utility & corporate investments" for noncurrent on the Condensed Consolidated Balance Sheets (unaudited).
(2) Presented in "Accrued liabilities" for current and "Deferred credits & other liabilities" for noncurrent on the Condensed Consolidated Balance Sheets (unaudited).
(3) Presented in "Other investments" on the Condensed Consolidated Balance Sheets (unaudited).
(4) Presented in "Deferred credits & other liabilities" on the Condensed Consolidated Balance Sheets (unaudited).

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

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

The Company's Indiana gas utilities entered into multiple five-year forward purchase arrangements to fix the price of natural gas for a portion of the Company's gas supply. These arrangements, approved by the IURC, replaced normal purchase or normal sale long-term physical fixed-price purchases. The Company values these contracts using a pricing model that incorporates market-based information, and are classified within Level 2 of the fair value hierarchy. Gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are refunded to or collected from customers through the Company's respective gas cost recovery mechanisms.

As described in Note 8, the Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging variability in interest rates. The Company values these contracts using a pricing model that incorporates market-based information, and are classified within Level 2 of the fair value hierarchy.

14. Impact of Recently Issued Accounting Standards

Leases
In February 2016, the FASB issued new accounting guidance, ASU 2016-02, for the recognition, measurement, presentation, and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019 and is required to be applied using a modified retrospective approach.

In January 2018, the FASB issued ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard. The Company currently anticipates that it will apply the election under 2018-01 to its existing or expired land easements as part of its transition.

In July 2018, the FASB issued ASU 2018-11, providing entities an optional transitional relief method to apply ASU 2016-02 at the adoption date and to recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company currently anticipates that it will apply the election under 2018-11 to its 2016-02 adoption.

The Company will adopt the guidance effective January 1, 2019 and is evaluating additional available practical expedients and the standard to determine the impact it will have on the financial statements. No material impact to net income is expected.

Other Recently Issued Standards
Management believes other recently issued standards, which are not yet effective, will not have a material impact on the Company's financial condition, results of operations, or cash flows upon adoption.

15. Segment Reporting

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

(In millions)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Revenues				
Gas Utility Services	$122.1	$120.4	$600.7	$557.2
Electric Utility Services	160.0	159.2	437.4	433.0
Other Operations	11.8	11.4	35.3	34.2
Eliminations	(11.7)	(11.3)	(35.1)	(34.0)
Total Revenues	$282.2	$279.7	$1,038.3	$990.4
Profitability Measure - Net Income				
Gas Utility Services	$(0.6)	$1.0	$60.7	$55.8
Electric Utility Services	30.6	27.2	62.4	56.8
Other Operations	3.0	2.6	9.7	9.6
Total Net Income	$33.0	$30.8	$132.8	$122.2

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

Description of the Business

Vectren Utility Holdings, Inc. (the Company, Utility Holdings, or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren or the Company's parent) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company 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 the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 598,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,000 electric customers and approximately 112,000 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 320,000 natural gas customers located near Dayton in west-central Ohio. The Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company's 2017 annual report filed on Form 10-K.

Merger with CenterPoint Energy, Inc.

On April 21, 2018, Vectren entered into an Agreement and Plan of Merger (the “Merger Agreement”), with CenterPoint Energy, Inc., a Texas corporation (“CenterPoint”), and Pacer Merger Sub, Inc., an Indiana corporation and wholly owned subsidiary of CenterPoint (“Merger Sub”). Pursuant to the Merger Agreement, and subject to the terms and conditions of the agreement, Merger Sub will merge with and into Vectren (the “Merger”), with Vectren continuing as the surviving corporation and becoming a wholly owned subsidiary of CenterPoint.

Subject to the terms and conditions in the Merger Agreement, upon closing, each share of common stock of Vectren shall be converted into the right to receive $72.00 in cash without interest.

Vectren, CenterPoint and Merger Sub each have made various representations, warranties and covenants in the Merger Agreement. Among other things, Vectren has agreed, subject to certain exceptions, to conduct its businesses in the ordinary course, consistent with past practice, from the date of the Merger Agreement until closing, and not to take certain actions prior to the closing of the Merger without the approval of CenterPoint. Vectren has made certain additional customary covenants, including, subject to certain exceptions: (1) to cause a meeting of Vectren's shareholders to be held to consider approval of the Merger Agreement, (2) not to solicit proposals relating to alternative business combination transactions and not to participate in discussions concerning, or furnish information in connection with, alternative business combination transactions and (3) not to withdraw its recommendation to Vectren's shareholders regarding the Merger. In addition, subject to the terms of the Merger Agreement, Vectren, CenterPoint and Merger Sub are required to use reasonable best efforts to obtain all required regulatory approvals, which will include clearance under federal antitrust laws and certain approvals by federal regulatory bodies, including FERC, subject to certain exceptions, including that such efforts not result in a "Burdensome Condition" (as defined in the Merger Agreement). While approval of the Merger Agreement is not required by the Indiana Utility Regulatory Commission ("IURC") or the Public Utilities Commission of Ohio ("PUCO"), informational filings have been made with each commission.

Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of Vectren, (2) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (3) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (4) absence of any law or order prohibiting the consummation of the Merger and (5) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to Vectren and its subsidiaries.

The Merger Agreement contains certain termination rights for both Vectren and CenterPoint, including if the Merger is not consummated by April 21, 2019 (subject to extension for an additional six months if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for each of Vectren and CenterPoint, and provides that, upon termination of the Merger Agreement under certain specified circumstances, CenterPoint would be required to pay a termination fee of $210 million to Vectren, and under other specified circumstances Vectren would be required to pay CenterPoint a termination fee of $150 million.

On June 15, 2018, Vectren and CenterPoint submitted their filings with the FERC and initiated informational proceedings with regulators in Indiana and Ohio. Further, on June 18, 2018, Vectren and CenterPoint submitted their filings pursuant to the Hart-Scott-Rodino Act and the Federal Communications Commission. On June 26, 2018, CenterPoint and Vectren received notice from the Federal Trade Commission granting early termination of the waiting period under the Hart-Scott-Rodino Act.
On July 16, 2018, Vectren filed a definitive proxy statement, and a Form 8-K including supplemental disclosures to the proxy statement, with the Securities and Exchange Commission in connection with the Merger. On July 24, 2018, the Federal Communications Commission provided the final approvals for the transfer of control of the Vectren subsidiaries which hold radio licenses. At the special shareholders meeting held on August 28, 2018, the Merger Agreement and the Merger, as well as other matters relating to the proposed Merger, were voted on and approved by Vectren's shareholders. On October 5, 2018, the FERC issued an order indicating its approval of the Merger. In Indiana, the IURC held a hearing on October 17, 2018 on Vectren's information filing. Final briefs are to be filed by December 21, 2018, and an order is expected in early 2019. A similar informational filing was made in Ohio and, though a hearing before the PUCO is not anticipated, an order is expected in early 2019, as well. As of November 6, 2018, seven purported Vectren shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in Vectren's proxy statement in connection with the Merger as discussed in Note 9. Subject to receipt of remaining approvals, Vectren continues to anticipate that the closing of the Merger will occur no later than the first quarter of 2019.

Executive Summary of Consolidated Results of Operations

In the third quarter of 2018, the Company's earnings were $33.0 million, compared to $30.8 million in 2017. In the nine months ended September 30, 2018, the Company earned $132.8 million, compared to $122.2 million in 2017. The Company's results in the quarter and year to date periods reflect increases from the continued investment in infrastructure replacement programs in Indiana and Ohio and favorable impact of weather in 2018 compared to 2017.

Use of Non-GAAP Performance Measures

Margin
Throughout this discussion, the terms Gas utility margin and Electric utility margin are used, which are non-GAAP measures. 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. These measures are not specifically defined by GAAP, and therefore, are non-GAAP. The Company believes Gas utility margins and Electric utility margins are better indicators of relative contribution than Gas utility revenues and Electric utility revenues, their

closest GAAP measures, since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers. These non-GAAP measures should not be considered a substitute for, or superior to, measures calculated in accordance with GAAP.

Results of Operations

Gas Utility Margin (Non-GAAP measure) (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)	2018	2017	2018	2017
Gas utility revenues	$122.1	$120.4	$600.7	$557.2
Cost of gas sold	24.5	23.9	211.4	174.0
Total gas utility margin (non-GAAP)	$97.6	$96.5	$389.3	$383.2
Margin attributed to:				
Residential & commercial customers	$72.8	$72.4	$290.2	$293.1
Industrial customers	14.8	15.9	52.6	53.1
Other	1.4	1.5	6.8	6.4
Regulatory expense recovery mechanisms	8.6	6.7	39.7	30.6
Total gas utility margin (non-GAAP)	$97.6	$96.5	$389.3	$383.2
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	5.9	6.0	76.6	59.3
Industrial customers	31.1	25.4	109.8	87.2
Total sold & transported volumes	37.0	31.4	186.4	146.5

Gas utility margins were $97.6 million and $389.3 million for the three and nine months ended September 30, 2018, and compared to 2017, increased $1.1 million quarter over quarter and $6.1 million year over year. Gas utility margins increased
$6.8 million in the quarter and $26.9 million year over year when excluding margin from regulatory expense recovery mechanisms, which increased $1.9 million quarter over quarter and $9.1 million year over year, and the impact of tax reform and the reduced corporate tax rate on margins, which in the quarter reduced margins by $7.6 million and year to date by $29.9. Gas margin was favorably impacted by increased returns on infrastructure replacement programs in Indiana and Ohio of $6.0 million quarter over quarter and $20.8 million year over year. Large customer margins were up $0.3 million quarter over quarter and $2.9 million year over year, largely driven by favorable weather compared to the first quarter of 2017. With rate designs that substantially limit the impact of weather on small customer margin, the normal weather in the first nine months of 2018 compared to the warmer than normal weather in the first nine months of 2017 increased sold and transported volumes, but had only a slight favorable impact on small customer margin. Heating degree days were 102 percent of normal in Ohio and 99 percent of normal in Indiana in the first nine months of 2018, compared to 89 percent of normal in Ohio and 80 percent of normal in Indiana in the same period in 2017.

Electric Utility Margin (Non-GAAP measure) (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)	2018	2017	2018	2017
Electric utility revenues	$160.0	$159.2	$437.4	$433.0
Cost of fuel & purchased power	47.5	44.1	137.7	128.8
Total electric utility margin (non-GAAP)	$112.5	$115.1	$299.7	$304.2
Margin attributed to:				
Residential & commercial customers	$73.6	$76.4	$192.6	$197.0
Industrial customers	25.0	26.4	69.6	73.2
Other	0.7	0.9	1.9	2.8
Regulatory expense recovery mechanisms	4.9	3.3	13.4	8.1
Subtotal: retail	$104.2	$107.0	$277.5	$281.1
Wholesale power & transmission system margin	8.3	8.1	22.2	23.1
Total electric utility margin (non-GAAP)	$112.5	$115.1	$299.7	$304.2
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	809.7	796.5	2,148.3	2,042.8
Industrial customers	613.6	587.8	1,668.6	1,600.7
Other customers	5.1	5.1	16.0	16.0
Total retail volumes	1,428.4	1,389.4	3,832.9	3,659.5
Wholesale	121.9	56.7	468.6	295.9
Total volumes sold	1,550.3	1,446.1	4,301.5	3,955.4

Retail
Electric retail utility margins were $104.2 million and $277.5 million for the three and nine months ended September 30, 2018, and compared to 2017, decreased by $2.8 million quarter over quarter and $3.6 million year over year. Electric retail utility margins increased $4.3 million quarter over quarter and $14.1 million year over year, when excluding margin from regulatory expense recovery mechanisms, which increased $1.6 million quarter over quarter and $5.3 million year over year, and the impact of tax reform and the reduced corporate tax rate on margins, which in the quarter reduced margins by $8.7 million and year to date by $23.0 million. Electric margin, which is not protected by weather normalizing mechanisms, reflects a $3.3 million increase in customer margin in the quarter and $12.3 increase year to date related to weather. In the quarter, annualized cooling degree days were 111 percent of normal, compared to 100 percent of normal in 2017. Year to date, annualized cooling degree days were 130 percent of normal, compared to 108 percent of normal in 2017. Year to date results also reflect favorable heating degree days, which were 99 percent of normal in the 2018 year to date period compared to 80 percent of normal in 2017.

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

	Three Months Ended	Nine Months Ended

	September 30,		September 30,	
(In millions)	2018	2017	2018	2017
MISO Transmission system margin	$ 7.0	$ 7.4	$ 17.7	$ 20.0
MISO Off-system margin	1.3	0.7	4.5	3.1
Total wholesale margin	$ 8.3	$ 8.1	$ 22.2	$ 23.1

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $7.0 million and $7.4 million during the three months ended September 30, 2018 and 2017, respectively. Transmission system margin was $17.7 million and $20.0 million during the nine months ended September 30, 2018 and 2017, respectively. The impact of tax reform reduced MISO Transmission system margins by $0.5 million and $1.0 million in the three and nine months ended September 30, 2018, respectively. The Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.9 million at September 30, 2018. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. These projects earn a FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued a final order authorizing the transmission owners to receive a 10.32 percent base ROE plus, a separately approved 50 basis point adder compared to the previously authorized 12.38 percent. The Company has reflected these outcomes in its financial statements. The 345 kV project is the largest of these qualifying projects, with an original cost of $106.8 million that earned the FERC approved equity rate of return.
In the third quarter of 2018, margin from off system sales was $1.3 million compared to $0.7 million in 2017. For the nine months ended September 30, 2018, margin from off-system sales was $4.5 million compared to $3.1 million in 2017. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year to be shared equally with customers. Results for the periods presented are net of sharing and are consistent with the prior period.

Operating Expenses

Other Operating
During the third quarter of 2018, other operating expenses were $83.5 million, an increase of $1.5 million, compared to the third quarter of 2017. For the nine months ended September 30, 2018, other operating expenses were $265.6 million, an increase of $15.2 million, compared to 2017. Excluding costs recovered directly in margin, operating expenses remained relatively flat, decreasing $1.8 million quarter over quarter and increased $2.3 million year over year when compared to 2017.

Depreciation & Amortization
In the third quarter of 2018, depreciation and amortization expense was $63.4 million, compared to $59.0 million in 2017. For the nine months ended September 30, 2018, depreciation and amortization expense was $186.3 million, which represents an increase of $12.0 million compared to 2017. The increases reflect increased plant placed in service, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Taxes Other Than Income Taxes
Taxes other than income taxes were $13.5 million and $12.6 million for the third quarter of 2018 and 2017, respectively. Year to date, taxes other than income taxes were $47.5 million, compared to $40.1 million in 2017. The increase in taxes other than income taxes in the quarter and year to date periods compared to 2017 was primarily related to higher property taxes, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Income Taxes
Income taxes were $5.7 million and $17.1 million for the third quarter of 2018 and 2017, respectively. Year to date, income taxes were $24.6 million, compared to $68.5 million in 2017. The decreases relate primarily to the decline in

the federal income tax rate from 35% to 21%, effective January 1, 2018, as well as the amortization of excess deferred income taxes beginning in the first quarter of 2018. Both the tax rate change and the excess deferred tax amortization relate directly to the passage of the TCJA in December 2017 and have associated revenue reductions.

Other Income - Net

Other income-net reflects income of $9.2 million for the third quarter of 2018, an increase of $1.1 million, compared to 2017. Year to date, other income-net reflects income of $27.9 million, compared to $21.4 million in 2017. The increases are primarily due to increased AFUDC driven by increased capital expenditures related to gas infrastructure investment programs.

Gas Rate & Regulatory Matters

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

Indiana Senate Bill 251 (Senate Bill 251) provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, based on the overall rate of return most recently approved by the IURC, through a base rate case or other proceeding, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs is deferred for future recovery in the utility's next general rate case.

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require, among other things, requests for recovery including a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, except for the rate of return on equity, which remains fixed at the rate determined in the Company's last base rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred for future recovery in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of not more than two percent.

Ohio House Bill 95 (House Bill 95) permits a natural gas utility to apply for recovery of much of its capital expenditure program. This legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post-in-service carrying costs until recovery is approved by the PUCO.

Requests for Recovery under Indiana Regulatory Mechanisms
In August 2014, the IURC issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the statutes, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

Since this August 2014 Order, the Company has received eight semi-annual orders which approved the inclusion in rates of approximately $563 million of approved capital investments through December 31, 2017.

On June 20, 2018, the Indiana Supreme Court issued an opinion (Opinion) in an appeal of an IURC order under Indiana Senate Bill 560 for a utility unrelated to the Company. In this Opinion, the Court determined that one of the programs within that utility’s approved plan did not constitute a “designated” capital improvement because the individual projects within the program were not specifically set forth in the approved seven-year plan, and, instead were designated later based on subsequently developed information. The IURC had previously approved the program and thereby allowed individual projects under the program to be designated in the future and that action was then appealed by intervenors in the TDSIC proceeding. The Company has evaluated the opinion's potential application to the Company’s Plan. The Company believes the ruling is limited to prospective projects that have not previously been designated and approved in final orders issued in the TDSIC process. The Company has determined that TDSIC projects in the service replacement plan category do not constitute a designated capital improvement, and therefore as a result of the Opinion is removing the associated projects that were not previously the subject of final orders, totaling approximately $40 million over the remaining term of the plan. Such projects are still eligible for recovery in a future base rate case. The Company does not expect a resulting material impact to results of operations or cash flow from operations.

On October 1, 2018, the Company submitted its ninth semi-annual filing, seeking approval of the recovery in rates of investments made through June 30, 2018, and updates to the approved seven-year capital investment plan. The updated plan reflects capital expenditures of approximately $955 million. The Company expects an order in this proceeding in early 2019.

At September 30, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $92.3 million and $78.0 million, respectively.

In December 2016, PHMSA issued interim final rules related to integrity management for storage operations. Efforts are underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage Safety Recommendations from a joint Department of Energy and PHMSA led task force. On August 3, 2017, the Company filed for authority to recover the associated costs using the mechanism allowed under Senate Bill 251. Approximately $15 million of operating expenses and $17 million of capital investments will be included in the plan over a four-year period beginning in 2018. The Company received the IURC Order approving the request for recovery on December 28, 2017. The Company does not have company-owned storage operations in Ohio.

Ohio Recovery and Deferral Mechanisms
The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In the Company's base rate case, it requested extension to include investments made starting 2018 through completion of the program, currently estimated at 2023. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $353.1 million as of September 30, 2018, of which $321.1 million has been approved for recovery under the DRR through December 31, 2017. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $36.5 million and $31.2 million at September 30, 2018 and December 31, 2017, respectively.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. The Company has requested recovery of these deferrals through December 31, 2017 in its rate case, along with a mechanism to recover future Ohio House Bill 95 deferrals. At September 30, 2018 and December 31, 2017, the Company has regulatory assets totaling $90.1 million and $66.1 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. On May 1, 2018, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Vectren Ohio Gas Rate Case

On March 30, 2018, the Company filed with the PUCO a request for a $34 million increase in its base rates and charges for VEDO’s distribution business in its 17 county service area in west-central Ohio. The requested increase includes the benefit of the TCJA, which decreased the corporate rate from 35 percent to 21 percent. The filing is necessary to extend the DRR mechanism beyond 2017 through completion of the accelerated replacement program, and to recover the costs of capital investments made over the past ten years, much of which has been deferred as part of the Company’s capital expenditure program under Ohio House Bill 95. The filing also addresses the recovery of the current Ohio House Bill 95 regulatory asset balance, and a proposed mechanism to recover future Ohio House Bill 95 deferrals.

On October 1, 2018, the PUCO staff filed its report of its audit in this proceeding, including recommendations for a revenue increase between $12 million and $16 million. Much of the reduction relates to periodic recovery mechanism versus base rate method of cost recovery, a reduction to the requested ROE, and a reduction to certain operating expenses. Staff was supportive of the continuation of the DRR and the expansion of straight-fixed-variable rate design to small commercial customers. The Company and other parties filed objections to the Staff report adjustments on October 31, 2018, and the Company will file supplemental testimony in early November 2018, continuing to support its filed position. The Commission has set the procedural schedule in this proceeding, with a prehearing conference scheduled for November 15, 2018, followed by three field hearings to occur in November and an evidentiary hearing to begin on December 4, 2018. The Company expects an order by early 2019.

Pipeline and Hazardous Materials Safety Administration (PHMSA)

In March 2016, PHMSA published a notice of proposed rulemaking (NOPR) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company continues to evaluate the impact these proposed rules will have on its integrity management programs and transmission and distribution systems. Progress on finalizing the rule continues to work through the administrative process. The rule is expected to be finalized in 2019 and the Company believes the costs to comply with the new rules would be considered federally mandated and therefore should be recoverable under Senate Bill 251 in Indiana and eligible for deferral under House Bill 95 in Ohio.

Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560

The provisions of Senate Bill 560, as described in Note 10 for gas projects, are the same for qualifying electric projects. On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company’s network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers.

On September 20, 2017, the IURC issued an Order approving the Company’s electric system modification as reflected in the settlement agreement reached between the Company, the OUCC, and a coalition of industrial customers. The settlement agreement includes defined annual caps on recoverable capital investments, with the total approved plan set at $446.5 million. The settlement agreement also addresses how the eligible costs would be recoverable in rates, with a cap on the residential and small general service fixed monthly charge per customer in each semi-annual filing. The remaining costs to residential and small general service customers would be recovered via a volumetric energy charge.

The settlement agreement removed advanced metering infrastructure (AMI or digital meters) from the plan. However, deferral of the costs for AMI was agreed upon in the settlement whereby the company can move forward with deployment in the near-term. The request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which is expected to be filed by the end of 2023. In that proceeding, settling parties have agreed not to oppose inclusion of the AMI project in rate base.

On December 20, 2017, the IURC issued an Order approving the initial rates necessary to begin cash recovery of 80 percent of the revenue requirement, inclusive of return, with the remaining 20 percent deferred for recovery in the utility's next general rate case. These initial rates captured approved investments made through April 30, 2017.

On May 23, 2018, the IURC issued an order (May 2018 order) for the second semi-annual filing approving the inclusion in rates of investments made from May 2017 through October 2017. Through the May 2018 order, approximately $31 million of the approved capital investment plan has been incurred and approved for recovery.

On August 1, 2018, the Company submitted its third semi-annual filing, seeking approval of the recovery in rates of approximately $58 million through April 2018.

On June 20, 2018, the Indiana Supreme Court issued an opinion (Opinion) in an appeal of an IURC order under Indiana Senate Bill 560 for a utility unrelated to the Company. In this Opinion, the Court determined that one of the programs within that utility's approved plan did not constitute a "designated" capital improvement because the individual projects within the program were not specifically set forth in the approved seven-year plan, and, instead were designated later based on subsequently developed information. The IURC had previously approved the program and thereby allowed individual projects under the program to be designated in the future and that action was then appealed by intervenors in the TDSIC proceeding. The Company has evaluated the opinion's potential application of the Company's Plan. The Company believes the ruling is limited to prospective projects that have not previously been designated and approved in final orders issued in the TDSIC process. The Company has determined that TDSIC projects in the pole replacement plan category that weren't previously the subject of final orders, totaling approximately $35 million, do not constitute a designated capital improvement eligible for recovery given this Opinion. As the Company has the ability under the electric plan to substitute projects with other approved projects within defined annual cost caps, the Company does not expect this Opinion to impact the total amount of the approved plan, and therefore does not expect a resulting material impact to results of operations or cash flow from operations. The Company removed the projects from the plan in accordance with the Opinion when it filed its third semi-annual TDSIC proceeding on August 1, 2018.

As of September 30, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $5.1 million and $4.3 million, respectively.

SIGECO Electric Environmental Compliance Filing

On January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. 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.

As of 2017, the Company has completed investments of $30 million on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of September 30, 2018, the Company has approximately $17.0 million deferred related to depreciation and operating expenses, and $6.1 million deferred related to post-in-service carrying costs. MATS compliance was required beginning April 16, 2015 and the Company continues to operate in full compliance with the

MATS rule.

On February 20, 2018, as part of the electric generation transition plan case discussed below, the Company filed a request to commence recovery, under Senate Bill 251, of its already approved investments associated with the MATS and NOV Compliance Projects, including recovery of the authorized deferred balance. As proposed, recovery would reflect 80 percent of the authorized costs, including a return, recovery of depreciation and incremental operating expenses, and recovery of the prior deferred balance over a proposed period of 15 years. The remaining 20 percent will be deferred until the Company’s next base rate proceeding. The Company expects an order in the first half of 2019.

SIGECO Electric Demand Side Management (DSM) Program Filing
On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, customers representing most of the eligible load have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also requires the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company’s 2016-2017 energy efficiency plan. The Order provided for cost recovery of program and administrative expenses and included performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that would have limited recovery related to new programs to the shorter of four years or the life of the installed energy efficiency measure. Prior electric energy efficiency orders did not limit lost margin recovery in this manner. This ruling followed other IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company appealed this lost margin recovery restriction based on the Company’s commitment to promote and drive participation in its energy efficiency programs.

On March 7, 2017, the Indiana Court of Appeals reversed the IURC finding on the Company's 2016-2017 energy efficiency plan that the four year cap on lost margin recovery was arbitrary and the IURC failed to properly interpret the governing statute requiring it to review the utility's originally submitted DSM proposal and either approve or reject it as a whole, including the proposed lost margin recovery. The case was remanded to the IURC for further proceedings. On June 13, 2017, the Company filed additional testimony supporting the plan. In response to the proposals to cap lost margin recovery, the Company filed supplemental testimony that supported lost margin recovery based on the average measure life of the plan, estimated at nine years, on 90 percent of the direct energy savings attributed to the programs. Testimony of intervening parties was filed on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 20, 2017, the Commission issued an order approving the DSM Plan for 2016-2017 including the recovery of lost margins consistent with the Company’s proposal. On January 22, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. Briefing is now complete. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission’s order, the Company expects to prevail in this appeal.

On April 10, 2017, the Company submitted its request for approval to the IURC of its Energy Efficiency Plan for calendar years 2018 through 2020. Consistent with prior filings, this filing included a request for continued cost recovery of program and administrative expenses, including performance incentives for reaching energy savings goals and continued recovery of lost margins consistent with the modified proposal in the 2016-2017 plan. Filed testimony of intervening parties was received on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 28, 2017, the Commission issued an order approving the 2018 through 2020 Plan, inclusive of recovery of lost margins consistent with the Order issued on December 20, 2017. On January 26, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. Briefing is now complete. While no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission’s order, the Company expects to prevail in this appeal.

For the nine months ended September 30, 2018 and 2017, the Company recognized electric utility revenue of $9.1 million and

$8.7 million, respectively, associated with lost margin recovery approved by the Commission.

FERC Return on Equity (ROE) Complaints

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against the MISO and various MISO transmission owners, including SIGECO (first complaint case). The joint parties sought to reduce the 12.38 percent base ROE used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent covering the refund period from November 12, 2013 through February 11, 2015 (first refund period). On September 28, 2016, the FERC issued a final order authorizing a 10.32 percent base ROE for the first refund period and prospectively through the date of the order in a second complaint case as detailed below.

A second customer complaint case was filed on February 11, 2015 covering the refund period from February 12, 2015 through May 11, 2016 (second refund period). An initial decision from the FERC administrative law judge on June 30, 2016, authorized a base ROE of 9.70 percent for the second refund period. The FERC was expected to rule on the proposed order in the second complaint case in 2017, which would authorize a base ROE for this period and prospectively from the date of the order. The timing of such action is uncertain.

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The adder is applied retroactively from January 6, 2015 through May 11, 2016 and prospectively from the September 28, 2016 order in the first complaint case.

The Company has reflected these results in its financial statements. As of September 30, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.9 million at September 30, 2018.

On April 14, 2017, the U.S. Court of Appeals for the District of Columbia circuit vacated the FERC Opinion in a prior case that established a new methodology for calculating ROE. This methodology was utilized in the final order in the Company's first complaint case, and the initial decision in the Company's second complaint case. The Appeals Court stated that FERC did not prove the existing ROE was not just and reasonable, failed to provide any reasoned basis for their selected ROE, and remanded to the FERC for further justification of its ROE calculation. On October 16, 2018, FERC issued an order in the case establishing a modified ROE calculation framework. The Company is evaluating the order to determine impacts, if any, on the Company's complaint cases, but does not expect any impact to be material.

Electric Generation Transition Plan

As required by Indiana regulation, the Company filed its 2016 Integrated Resource Plan (IRP) with the IURC on December 16, 2016. The State requires each electric utility to perform and submit an IRP that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next twenty-year period. During 2016, the Company held three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progressed. In developing its IRP, the Company considered both the cost to continue operating its existing generation units in a manner that complies with current and anticipated future environmental requirements, as well as various resource alternatives, such as the use of energy efficiency programs and renewable resources as part of its overall generation portfolio. After submission, parties to the IRP provided comments on the plan. While the IURC does not approve or reject the IRP, the process involves the issuance of a staff report that provides comments on the IRP. The final report was issued on November 2, 2017. The Company has taken the comments provided in the report into consideration in its generation transition plan.

The Company’s IRP considered a broad range of potential resources and variables and is focused on ensuring it offers a reliable, reasonably priced generation portfolio as well as a balanced energy mix. Consistent with the recommendations presented in the Company’s IRP and as a direct result of significant environmental investments required to comply with current regulations, the Company plans to retire a significant portion of its generating fleet by the end of 2023. On February 20, 2018, the Company filed a petition seeking authorization from the IURC to construct a new 800-900 MW natural gas combined cycle generating facility to replace this capacity at an approximate cost of $900 million, which includes the cost of a new natural gas pipeline to serve the plant. The Company is requesting a certificate of public convenience and necessity (CPCN) authorizing construction timelines and costs of new generation resources, as well as necessary unit retrofits, to implement the generation transition plan. In that filing, the Company seeks approval of its generation transition plan, including the authority to defer the cost of new generation, including the ability to accrue AFUDC and defer depreciation until the facility is placed in base rates.

As a part of this same proceeding, the Company seeks recovery under Senate Bill 251 of costs to be incurred for environmental investments to be made at its F.B. Culley generating plant to comply with Effluent Limitation Guidelines and Coal Combustion Residuals rules. The F.B. Culley investments, estimated to be approximately $95 million, will begin in 2019 and will allow the F.B. Culley Unit 3 generating facility to comply with environmental requirements and continue to provide generating capacity to the Company’s electric customers. Under Senate Bill 251, the Company is seeking recovery of 80 percent of the approved costs, including a return, using a tracking mechanism, with the remaining 20 percent of the costs deferred for recovery in the Company’s next base rate proceeding.

On August 10, 2018, most of the intervening parties filed direct testimony opposing the Company’s proposed generation investments, and an evidentiary hearing has been completed. The Company continues to support the proposed investments and expects an order from the Commission in the CPCN proceeding in the first half of 2019.

On August 30, 2017, the IURC issued an Order approving the Company’s request to recover costs related to the construction of three solar projects, using the mechanism allowed under Senate Bill 29, which allows for timely recovery of costs and expenses incurred during the construction and operation of clean energy projects. These investments, presented as part of the Company’s (IRP) submitted in December 2016, allow the Company to add approximately 4 MW of universal solar generation, rooftop solar generation, and 1 MW of battery storage resources to its portfolio. The approved cost of the projects cannot exceed the approximate $16 million estimate submitted by the Company, without seeking further Commission approval.

On February 20, 2018, the Company announced it is finalizing details to install an additional 50 MW of universal solar energy, consistent with its IRP. On May 4, 2018, the Company filed a petition with the IURC requesting a CPCN authorizing construction and authority to recover costs associated with the project pursuant to Senate Bill 29. On September 5, 2018, the intervening parties filed testimony opposing the investment, and on September 18, 2018 the Company filed its rebuttal testimony in response. On October 10, 2018, a settlement agreement between all but one of the intervening parties and Vectren was filed. The settlement agreement provides for a rate recovery approach whereby the energy produced by the solar farm would be recovered via a fixed rate over the life of the investment. The settlement is now pending before the Commission, with an evidentiary hearing scheduled for November 19, 2018. The Company would expect an order in the first half of 2019.

Other Generation Developments

On September 21, 2017, the Company and Alcoa agreed to continue the joint ownership and operation of Warrick Unit 4 through 2023. This aligns with the Company's long-term electric generation transition plan, and the expected exit at the end of 2023 is consistent with the IRP which reflects having completed all planned unit retirements and bringing new resources online by that date.

On September 28, 2017, the Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR) to the FERC for consideration of payment to certain resources that have on-site fuel and demonstrate a form of resilience. On January 8, 2018, after receiving a majority of comments from the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) opposing the relief requested by the DOE, the FERC declined to issue the NOPR and, instead, initiated a proceeding (FERC Docket No. AD18-7) to further explore the current planning that RTOs and ISOs are undertaking to ensure resiliency, as well as other regional aspects to determine the need for action of the type recommended by the DOE. This proceeding is still pending before the FERC. In the interim, a draft memorandum that was purportedly prepared by the DOE was made public on May 31, 2018. The draft memorandum calls for immediate action by the President of the United States to exercise authority under the Defense Production Act and Federal Power Act to provide for temporary subsidy payments to coal and nuclear resources while a two year study is performed to identify Defense Critical Electric Infrastructure (DCEI). The draft memorandum expands upon the original resiliency concerns expressed in the DOE's September 28, 2017 submission.
Following the publication of the draft DOE memorandum, the President publicly called for immediate action by the DOE. To date, the DOE has not publicly acted, including finalizing the draft memorandum and indicating facilities

that would be eligible for these temporary subsidy payments or how they would be funded. At this time, the Company does not believe this activity will have any impact on its pending request for authorization from the IURC to construct a combined cycle gas turbine to serve the requirements of the Company's electric utility system. Absent further information, the impact to electric customers and power generator owners is unknown.

Environmental & Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report. Since that time, the Company continues to develop strategies that focus on environmental, social, and governance (ESG) factors that contribute to the long-term growth of a sustainable business model. The sustainability policies and efforts, and in particular its policies and procedures designed to ensure compliance with applicable laws and regulations, are directly overseen by the Company's Corporate Responsibility and Sustainability Committee, as well as vetted with the Company's Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in the Company’s current sustainability report, at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

In furtherance of the Company’s commitment to a sustainable business model, and as detailed further below, the Company is transitioning its electric generation portfolio from nearly total reliance on baseload coal to a fully diversified and balanced portfolio of fuels that will provide long term electric supply needs in a safe and reliable manner while dramatically lowering emissions of carbon and the carbon intensity of its electric generating fleet. If authorized by the Commission, by 2024 the Company plans to construct a new natural gas combined cycle generating facility to replace four coal-fired units totaling over 700 MWs which, when combined with its planned 54 MWs of new renewable generation, will achieve a 60 percent reduction in carbon emissions from 2005 levels and reduce carbon intensity to 980 lbs CO_2 / MMBTU and position the Company to comply with future carbon emission reduction requirements. In addition to diversification of its fuel portfolio, the Company is also seeking authorization to significantly upgrade wastewater treatment for its remaining coal-fired unit and exploring opportunities to continue to recycle ash from its coal ash ponds. This generation diversification strategy aligns with the Company’s ongoing investments in new electric infrastructure through the approved $446.5 million grid modernization program, and is set forth in more detail in the Company’s 2017 corporate sustainability report.

Further, as part of its commitment to a culture of compliance excellence and continuous improvement, the Company continues to enhance its Safety Management System (SMS) which was implemented several years ago. The risk analysis and process review provides valuable input into the assessment process used to drive the ongoing infrastructure improvement plans being executed by the Company’s gas and electric utilities.

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury, among others.
Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it

relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August 2017, the EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. On July 17, 2018, EPA released its final CCR rule phase I reconsideration which extends for two years, from October 31, 2018 to October

31, 2020, the deadline for ceasing placement of ash in ponds that exceed groundwater protections standards or fails to meet location restrictions. The Company does not anticipate the reconsideration to change its current plans for pond closure as announced in its generation transition plan, since closure dates were not dependent upon the original October 2018 compliance date. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect. On August 21, 2018, the U.S. Court of Appeals for the D.C. Circuit issued an opinion in the underlying judicial review litigation, agreeing largely with the environmental challengers by vacating and remanding provisions of the 2015 rule that allowed unlined ash ponds to receive coal ash until a leak is detected and exempted inactive “legacy” impoundments. This decision effectively undercuts further attempts by EPA to make the rule less stringent on reconsideration.

Under the existing CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility. In March 2018, the Company posted to its public website a first report of preliminary groundwater monitoring data in accordance with the requirements of the CCR rule. This data preliminarily suggests potential groundwater impacts very close to the Company's ash impoundments, and further analysis is ongoing; however, at this time the Company does not believe that there are any impacts to public or private drinking water sources. The CCR rule requires that companies complete location restriction determinations by October 18, 2018. The Company has completed its evaluation under the rule and determined that one F.B. Culley pond and one A.B. Brown pond fail the aquifer placement location restriction requiring that ash cannot be disposed within five feet of the uppermost groundwater aquifer. The Company will be required to cease disposal and commence closure of the ponds by October 31, 2020. The Company plans to seek the extensions available under the CCR rule that would allow the Company to continue to use the ponds through completion of the generation transition plans by December 31, 2023.

Since 2015, the Company continues to refine site specific estimates and now estimates the costs to be in the range of $45 million to $135 million. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. Current estimates contemplate complete removal under the assumption of beneficial reuse of the ash at A. B. Brown, as well as implications of the Company’s generation transition plan. Ongoing analysis, the continued refinement of assumptions, or the inability to beneficially reuse the ash, either from a technological or economical perspective, could result in estimated costs in excess of the current range.

As of September 30, 2018, the Company has recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company spent approximately $17 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

On July 20, 2018, the Company filed a Complaint for Damages and Declaratory Relief against its insurers seeking reimbursement of defense, investigation, and pond closure costs incurred to comply with the CCR rule. The Company intends to apply any net proceeds from this litigation to offset costs that have been and will be deferred for future recovery from customers.

Effluent Limitation Guidelines (ELG)

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. In September 2015, the EPA finalized revisions to the existing steam electric ELG setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELG will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELG work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company’s IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by IDEM provided the Company notifies IDEM of its intent to retire the unit within 30 days of the receipt of the order in the CPCN proceeding. For the F.B. Culley 3 plant, the Company requested a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by IDEM and finalized in the permit renewal. Discussion of these environmental investments at the F.B. Culley 3 plant is included in the generation transition plan in Note 11.

On April 13, 2017, as part of the Administration's regulatory reform initiative, which is focused on the number and nature of regulations, the EPA granted petitions to reconsider the ELG rule, and indicated it would stay the current implementation deadlines in the rule during the pendency of the reconsideration. On September 13, 2017, EPA finalized a rule postponing certain interim compliance dates by two years, but did not postpone the final compliance deadline of December 31, 2023. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not anticipate immediate impacts from the EPA’s two-year extension of preliminary implementation deadlines due to the longer compliance time frames granted by IDEM, and will continue to work with IDEM to evaluate further implementation plans. Moreover, the Company believes the two year extension of the ELG preliminary implementation deadlines and reconsideration process does not impact its generation transition plan as modeled in the IRP because the final compliance deadline of December 31, 2023 is still in place and enhanced wastewater treatment for scrubber discharge water will still be required by a reconsidered ELG rule even if the EPA revises stringency levels.

Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires generating facilities use the “best technology available” (BTA) to minimize adverse environmental impacts on a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. A final rule was issued by the EPA on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires that IDEM conduct a case-by-case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company’s facilities. On July 23, 2018, the U.S. Court of Appeals for the Second Circuit upheld the final rule on judicial review. The Company is currently undertaking the required ecological studies and anticipates timely compliance in 2021-2022. To comply, the Company believes capital investments will likely be in the range of $4 million to $8 million.

Air Quality

Ozone NAAQS

On November 26, 2014, the EPA proposed to tighten the current National Ambient Air Quality Standard (NAAQS) for ozone from the current standard of 75 parts per billion (ppb) to a level within the range of 65 to 70 ppb. On

October 1, 2015, the EPA finalized a new NAAQS for ozone at the high end of the range, or 70 ppb. On September 16, 2016, Indiana submitted its initial determination to the EPA recommending counties in southwest Indiana, specifically Vanderburgh, Posey and Warrick, be declared in attainment of the new more stringent ozone standard based upon air monitoring data from 2014-2016. In November 2017, EPA finalized its designations of Vanderburgh, Posey, and Warrick counties as being in attainment with the current 70 ppb standard.

One Hour SO_2 NAAQS

On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between IDEM and the

EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO2 NAAQS. Identified on the list was Posey County, Indiana, where the Company's A.B. Brown Generating Station is located. While the Company is in compliance with all applicable SO2 limits in its permits, the Company reached an agreement with IDEM on voluntary measures the Company was able to implement without significant incremental costs to ensure Posey County remains in attainment with the 2010 One Hour SO2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Climate Change and Carbon Strategy

The Company, along with the Company's parent remains committed to responsible environmental stewardship and conservation efforts. The generation transition plan, as set forth in its generation and compliance filing, is a balanced approach toward environmental stewardship and conservation goals, supplying service at a reasonable cost, and operating in compliance with water, air and solid waste regulations, while dramatically reducing the Company's carbon emission from its electric generating fleet. The generation transition plan will result in a 60 percent reduction in carbon emissions from 2005 to 2024 even in the absence of a mandatory greenhouse gas reduction requirement. While the status of the Clean Power Plan (CPP) regulation is uncertain given the legal challenges it faces and pending proposal to repeal the CPP which, if finalized, would likely result in more litigation, the Company's generation transition plan positions it to comply with the CPP, its replacement rule, or future carbon legislation. Moreover, the Company's actions in reducing its carbon emissions 60 percent from 2005 levels by 2024 is consistent with the international community's goal of preventing global temperatures from rising more than two degrees Celsius by the year 2100.

While regulatory uncertainties predominate with respect to the status of the CPP, the Company continues to believe that Congress should set a broad national climate change policy with the following elements:

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

Current Initiatives to Increase Conservation & Reduce Emissions

Even in the absence of a federal mandatory requirement to reduce greenhouse gases, the Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Since 2005 and through 2017, the Company has achieved a reduction in emissions of CO2 of 30 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. The three year average emission reduction for the period 2015 to 2017 is 35 percent from 2005 levels.
- Focusing the Company’s mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report continues to receive Core level certification by the Global Reporting Initiative and demonstrates the Company's commitment to sustainability and transparency in operations. The Company's current sustainability report can be found at www.vectren.com/sustainability;
- Implementing home and business energy efficiency initiatives in the Company’s Indiana and Ohio gas utility service territories such as offering rebates on high efficiency furnaces, programmable thermostats, and insulation and duct

sealing;

- Implementing home and business energy efficiency initiatives in the electric service territory such as rebate programs on central air conditioning units, LED lighting, home weatherization and energy audits;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future

environmental compliance plans;

- Further reducing the Company’s carbon footprint by building a more sustainable vehicle fleet with lower overall fuel consumption;
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets; and
- Working with the Company’s gas supply administrator in Indiana to maximize the amount of natural gas delivered to our customers that has been sourced from members of The Environmental Partnership, an organization that includes many of the major oil and gas producers in the U.S and who have committed to continuously improving the industry’s environmental performance.

Clean Power Plan and ACE Rule

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which required a 32 percent reduction in carbon emissions from 2005 levels. This would result in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030 and implemented through a state implementation plan. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states’ and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA’s reconsideration of the CPP rule, which was granted on April 28, 2017. Moreover, as indicated above, in October 2017, EPA published its proposal to repeal the CPP. Comments to the repeal proposal were due in April 2018. EPA's repeal proposal was quickly followed by an advanced notice of proposed rulemaking intended to solicit public comments on issues related to formulating a CPP replacement rule, which were similarly due in April 2018.

On August 31, 2018, EPA published its proposed CPP replacement rule, the Affordable Clean Energy (ACE) rule, which if finalized, would require that each state set unit by unit heat rate performance standards, considering such factors as remaining useful life. Under the ACE rule, a state would have three years to finalize its program and the EPA would have 18 months to approve, making compliance likely in 2023-2024. Comments to the ACE proposal were due October 31, 2018. Vectren filed comments which largely support EPA's ACE proposal.

Impact of Legislative Actions & Other Initiatives

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. However, Vectren's generation transition plan, as set forth in its electric generation and compliance filing, will achieve 60 percent reductions in 2005 GHG emission levels by 2025, positioning the Company to comply with future regulatory or legislative actions with respect to mandatory GHG reductions.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28 percent GHG emission reduction from 2005 levels by 2025. The Administration has indicated it intends to withdraw the United States' participation; however, the Agreement provides that parties cannot petition to withdraw until November 2019. Since 2005 through 2017, the Company has achieved reduced emissions of CO_2 by an average of 35 percent (on a tonnage basis), and will increase that total to 60 percent at the conclusion of its generation transition plan, well above the 32 percent reduction that would be required under the CPP. While the litigation and the EPA's reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.7 million ($23.9 million at Indiana Gas and $20.8 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.8 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of September 30, 2018 and December 31, 2017, approximately $2.8 million and $2.5 million, respectively of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Standards

Leases
In February 2016, the FASB issued new accounting guidance, ASU 2016-02, for the recognition, measurement, presentation, and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019 and is required to be applied using a modified retrospective approach.

In January 2018, the FASB issued ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard. The Company currently anticipates that it will apply the election under 2018-01 to its existing or expired land easements as part of its transition.

In July 2018, the FASB issued ASU 2018-11, providing entities an optional transitional relief method to apply ASU 2016-02 at the adoption date and to recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company currently anticipates that it will apply the election under 2018-11 to its 2016-02 adoption.

The Company will adopt the guidance effective January 1, 2019 and is evaluating additional available practical expedients and the standard to determine the impact it will have on the financial statements. No material impact to net income is expected.

Other Recently Issued Standards

Management believes other recently issued standards, which are not yet effective, will not have a material impact on the Company's financial condition, results of operations, or cash flows upon adoption.

Financial Condition

Utility Holdings funds the short-term and long-term financing needs of its utility subsidiaries. The Company's parent does not guarantee the Company's debt. Outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 4 to the condensed consolidated financial statements. Long-term debt and short-term obligations outstanding at September 30, 2018 approximated $1.345 billion and $225 million, respectively. Additionally, prior to the Company's 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 new tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at September 30, 2018 was approximately $384 million.

The Company’s operations have historically been the primary source for Vectren’s common stock dividends.

The credit ratings of the senior unsecured debt of the Company, SIGECO and Indiana Gas, at September 30, 2018, were A-/A2, as rated by S&P Global Ratings (S&P Global) and Moody’s Investor Services (Moody’s), respectively. The credit ratings on SIGECO's secured debt were A/Aa3. The Company's commercial paper had a credit rating of A-2/P-1. S&P Global and Moody’s
lowest level investment grade rating is BBB- and Baa3, respectively.

On March 9, 2018, S&P Global affirmed its credit ratings, but changed the Company's and subsidiaries' outlook from stable to negative, citing the impacts of tax reform as the primary driver. On April 24, 2018, S&P Global reaffirmed its current ratings, and as a result of the Merger, it placed the Company's and subsidiaries on negative watch, which means closely monitored for potential near term changes in its credit ratings. On October 10, 2018 and October 16, 2018, S&P issued new reports on the Company and its subsidiaries, respectively, affirming the A- credit rating and negative outlook. On June 18, 2018, Moody's issued a report noting the rating agency has shifted its outlook on the regulated utility industry to negative, citing weaker cash flows resulting from tax reform including the loss of bonus depreciation, higher leverage due to the reduced cash flow, and continued capital spending. On October 8, 2018, Moody's affirmed the current credit rating of the Company and its subsidiaries, but changed the outlook from stable to negative, citing the effects of tax reform including the loss of bonus depreciation, and high level of capital expenditures.

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 to long-term capitalization ratio was 50 percent and 52 percent as of September 30, 2018 and December 31, 2017, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholder’s equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of September 30, 2018, the Company was in compliance with all debt covenants.

Available Liquidity

The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and as evidenced by past financing transactions, the Company believes it will have the ability to continue to do so. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds, supplemented with incremental external financing. Access to both the short-term and long-term capital markets is expected to be a significant source of funding for capital requirements as the resources required for capital investment remain uncertain for a variety of factors including, but not limited to, uncertainty in environmental and safety policy and regulations and growth in gas and electric infrastructure. To the extent that events beyond the Company's control create uncertainty in capital markets, cost of capital and ability to access capital markets may be impacted.

Utility Holdings routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. This authority allows for the flexibility for each utility to issue debt and equity securities to third parties or to issue debt and equity securities to Utility Holdings and thus receive some of the proceeds from various Utility Holdings issuances to third parties on the same terms as those obtained by Utility Holdings. The majority of the long-term debt needs of the utilities is expected to be met through these debt issuances by Utility Holdings, some or all of which are then reloaned to the individual utilities. Remaining financing authority, granted from the IURC and PUCO, is expected to be sufficient to meet the financing needs of the utilities.

Utility Holdings Term Loan
On July 30, 2018, Utility Holdings executed a term loan agreement and closed a two-year term loan with two banking partners. The term loan agreement provides for a $250 million draw at closing and $50 million on or prior to December 31, 2018. Proceeds from the term loan have been utilized to pay a $100 million August 1, 2018, debt maturity and for general utility purposes. The term loan's interest rate is currently priced at one month LIBOR, plus a credit spread, which is subject to change based on changes in Utility Holdings' credit rating. A change in credit rating would add approximately 10 basis points, per rating notch, to the existing rate. In addition, the term loan contains a provision that should Utility Holdings or any of its subsidiaries execute certain capital market transactions, and subject to certain other conditions, the outstanding balance is subject to mandatory prepayment. The term loan is jointly and severally guaranteed by Utility Holdings' wholly-owned operating companies, SIGECO, Indiana Gas, and VEDO.

SIGECO Variable Rate Tax-Exempt Bonds
On March 1, 2018 and May 1, 2018, the Company, through SIGECO, executed first and second amendments to a Bond Purchase and Covenants Agreement originally signed in September 2017. These amendments provided SIGECO the ability to remarket bonds that were callable from current bondholders on those dates. Pursuant to these amendments, lenders purchased the following SIGECO bonds on March 1 and May 1, respectively:
- 2013 Series A Notes with a principal of $22.2 million and final maturity date of March 1, 2038; and
- 2013 Series B Notes with a principal of $39.6 million and final maturity date of May 1, 2043.

Prior to the call, the 2013 Series A Notes had an interest rate of 4.0% and the 2013 Series B Notes had an interest rate of 4.05%. The bonds converted to a variable rate based on the one month LIBOR through May 1, 2023.

The Company has now remarketed $152 million of tax exempt bonds through the Bonds Purchase and Covenants Agreement, which is the agreement's full capacity. Bonds remarketed through the Bond Purchase and Covenants Agreement in 2017 were:
- 2013 Series C Notes with a principal of $4.6 million and final maturity date of January 1, 2022;
- 2013 Series D Notes with a principal of $22.5 million and final maturity date of March 1, 2024;
- 2013 Series E Notes with a principal of $22.0 million and final maturity date of May 1, 2037; and
- 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025.

These bonds also have a variable interest rate based on the one month LIBOR through May 1, 2023.

The Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the variability in interest rates on the 2013 Series A, B, and E Notes through final maturity dates. The swaps contain customary terms and conditions and generally provide offset for changes in the one month LIBOR rate. Other interest rate variability that may arise through the Bond Purchase and Covenants

Agreement, such as variability caused by changes in tax law or SIGECO's credit rating, among others, may result in an actual interest rate above or below the anticipated fixed rate. Regulatory orders require SIGECO to include the impact of its interest rate risk management activities, such as gains and losses arising from these swaps, in its cost of capital utilized in rate cases and other periodic filings.

Consolidated Short-Term Borrowing Arrangements

At September 30, 2018, the Company had $400 million of short-term borrowing capacity. As reduced by borrowings currently outstanding, approximately $175 million was available. These short-term credit facilities were extended in July 2017 and are available through July 2022.

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

(In millions)	2018	2017
As of September 30		
Balance Outstanding	$225.3	$211.7
Weighted Average Interest Rate	2.34%	1.39%
Year to Date Average - September 30		
Balance Outstanding	$177.2	$161.6
Weighted Average Interest Rate	2.18%	1.22%
Maximum Month End Balance Outstanding	$262.0	$238.7

(In millions)	2018	2017
Quarterly Average - September 30		
Balance Outstanding	$191.5	$210.9
Weighted Average Interest Rate	2.31%	1.41%
Maximum Month End Balance Outstanding	$225.3	$238.7

Impact of Tax Reform on Liquidity

The Company has realized cash flow benefits from tax legislation, such as the Protecting Americans from Tax Hikes (Path Act) enacted in 2015, which allowed for immediate expensing of 50 percent of capital expenditures through 2017 for tax purposes. Such accelerated expense recognition reduced tax payments due to the government. The TCJA enacted on December 22, 2017, which eliminates the accelerated expensing provisions for regulated utilities and reduces the corporate tax rate to 21 percent, has reduced, and will continue to reduce liquidity by 1) reducing the Utility Group's ability to accelerate expense for capital expenditures for tax purposes and 2) reducing cash collected from customers due to the lower tax rate. The Company further expects that the reduced federal corporate income tax rate could result in additional cash available from Vectren's nonutility operations to help fund utility capital expenditures or other operating needs.

Utility Holdings Borrowing Arrangements

The Merger would constitute a "Change of Control" under the note agreements pursuant to which Senior Notes issued by Utility Holdings in an aggregate principal amount of $1.025 billion were issued. While the Merger would not result in an event of default under such note agreements, upon the consummation of the Merger the issuer would be required to offer to repurchase these notes at 100% of the principal amount thereof plus accrued interest.

The Merger will represent an event of default pursuant to Utility Holdings' short-term credit facility, and Utility Holdings is in process of seeking a waiver from the facility bank group of this event of default. If a waiver is not obtained, upon closing of the merger, CenterPoint will fund the obligations associated with the credit facility.

Potential Uses of Liquidity

Pension Funding Obligations

For the nine months ended September 30, 2018, the Company's parent contributed $3.5 million to its qualified pension plans, a majority of which was funded by the Company. The Company's parent does not anticipate making any additional contributions for the remainder of 2018.

Planned Capital Expenditures
Capital expenditures are estimated at approximately $150 million for the remainder of 2018.

Contractual Obligations
The Company’s contractual obligations primarily consist of debt issued by the Company and its subsidiaries as well as certain plant and nonutility plant purchase commitments. For the nine months ended September 30, 2018, there were no significant changes to the Company’s contractual obligations from those identified in the Company’s Annual Report on Form 10-K for the year ended December 31, 2017, other than those which occur in the normal and ordinary course of business and those mentioned below.

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

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 $321.2 million and $338.2 million for the nine months ended September 30, 2018 and 2017, respectively. The decrease in operating cash flow for the nine months ended September 30, 2018 compared to 2017 is driven primarily by the Company’s $35.7 million contribution to the Vectren Foundation, a 501(c)(3) charitable organization, affiliated with, but separate from, Vectren Corporation and reflected in Accounts payable at December 31, 2017 in the Condensed Consolidated Balance Sheets.

Financing Cash Flow
Net cash flow required for financing activities were $100.8 million and $68.6 million during the nine months ended September 30, 2018 and 2017, respectively. The increase in financing cash flow for the nine months ended September 30, 2018 compared to 2017 is driven primarily by the $250 million term loan proceeds partially utilized to pay the $100 million long-term debt maturity and short-term borrowings utilized to fund the Vectren Foundation and increased capital expenditures. Financing activity in both periods reflects the payment of dividends to the Company's parent.

Investing Cash Flow
Cash flow required for investing activities was $424.8 million and $410.4 million during the nine months ended September 30, 2018 and 2017, respectively. The primary use of cash in both periods reflects expenditures for capital expenditures.

Forward-Looking Information

A “safe harbor” for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in this Quarterly Report on Form 10-Q are forward-looking statements, including but not limited to, statements concerning the expected timing, outcome, and operational and financial impacts of ongoing litigation, regulatory proceedings, proposed environmental regulations, legislative actions, and accounting standards, as well as statements concerning estimated future revenues, capital expenditures, and financing needs. 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 similar expressions are intended to forward-looking statements.

Risks Related to the Merger

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Important factors that could cause actual results to differ materially from those indicated by the provided forward-looking information include risks and uncertainties relating to:

- The risk that CenterPoint or Vectren may be unable to obtain governmental and regulatory approvals required for the proposed transaction, or that required governmental and regulatory approvals or agreements with other parties interested therein may delay the proposed transaction or may be subject to or impose adverse conditions or costs.
- The occurrence of any event, change or other circumstances that could give rise to the termination of the proposed transaction or could otherwise cause the failure of the proposed transaction to close.
- The risk that a condition to the closing of the proposed transaction or the committed financing may not be satisfied.
- The outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the proposed transaction.
- The receipt of an unsolicited offer from another party to acquire assets or capital stock of Vectren that could interfere with the proposed transaction.
- The timing to consummate the proposed transaction.
- The costs incurred to consummate the proposed transaction.
- The possibility that the expected cost savings, synergies or other value creation from the proposed transaction will not be realized, or will not be realized within the expected time period.
- The risk that the companies may not realize fair values from properties that may be required to be sold in connection with the merger.
- The credit ratings of the companies following the proposed transaction.
- Disruption from the proposed transaction making it more difficult to maintain relationships with customers, employees, regulators or suppliers.
- The diversion of management time and attention on the proposed transaction.

Risks Related to the Company

Important factors related to the Company, its affiliates, and its and their operations that could cause actual results to differ materially from those indicated by the provided forward-looking information include risks and uncertainties relating to:

- Factors affecting utility operations such as unfavorable or unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- New or proposed legislation, litigation and government regulation or other actions, such as changes in, rescission of or additions to tax laws or rates, pipeline safety regulation and environmental laws and regulations, including laws governing air emissions, carbon, waste water discharges and the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of generation plant costs and related assets. Compliance with respect to these regulations could substantially change the operation and nature of the Company’s utility operations.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, or physical attacks adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Cyber attacks or similar occurrences may adversely affect the Company's facilities, operations, corporate reputation, financial condition, and results of operations.

- Approval and timely recovery of new capital investments related to the electric generation transition plan, discussed further herein, including timely approval to build and own generation, ability to meet capacity requirements, ability to procure resources needed to build new generation at a reasonable cost, ability to appropriately estimate costs of new generation, the effects of construction delays and cost overruns, ability to fully recover the investments made in retiring portions of the current generation fleet, scarcity of resources and labor, and workforce retention, development and training.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.

- Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, 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, commodity prices, and monetary fluctuations.
- Economic conditions, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity; economic impacts of changes in business strategy on both gas and electric large customers; lower residential and commercial customer counts; variance from normal population growth and changes in customer mix; and higher operating expenses.
- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.
- Direct or indirect effects on the Company’s business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee or contractor workforce factors including changes in key executives, retention of key employees, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

The Company's parent has 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 Company's 2017 Form 10-K and is therefore not presented herein.

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ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended September 30, 2018, there have been no changes to the Company’s internal control 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, 2018, 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, 2018, 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 likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate & regulatory matters. The condensed consolidated financial statements are included in Part 1 Item 1.

As of November 13, 2018, seven purported Vectren shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in the Vectren's proxy statement in connection with the merger as discussed in Footnote 9 to the consolidated financial statements. We believe that these complaints are without merit. We cannot predict the outcome of, or estimate the possible loss or range of loss from, these matters.

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. Other than the merger-related risk factors noted below, the Company’s risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Company's 2017 Form 10-K and are therefore not presented herein.

Risks Associated with Merger

Vectren cannot provide any assurance that the Merger will be completed. Failure to complete the Merger could negatively affect the trading price of Vectren's common stock and the Company's future business and financial results.

Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of the Vectren, (2) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (3) absence of any law or order prohibiting the consummation of the Merger and (4) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to the Vectren and its subsidiaries.

The conditions to the Merger may not be satisfied and the Merger Agreement could be terminated. In addition, satisfying the conditions to the Merger may take longer than Vectren and CenterPoint expect. The completion of the merger may also be delayed by shareholder lawsuits filed under federal securities laws. The occurrence of any of these events individually or in combination could negatively affect the trading price of the Vectren's common stock and Vectren's future business and financial results and subject Vectren to the following:

- negative reactions from the financial markets, including declines in the price of the Vectren's common stock due to the fact that the current price may reflect a market assumption that the Merger will be completed;
- performance shortfalls and missed opportunities as a result of the diversion of the Company's management's attention by the Merger; and
- potential payments by Vectren to CenterPoint for damages, or if the Merger Agreement is terminated under certain circumstances, a termination fee of $150 million.

The Company will be subject to business uncertainties and contractual restrictions while the Merger is pending, which could adversely affect the Company's business.

Uncertainty about the impact of the Merger, including on employees and customers, may have an adverse effect on the Company. These uncertainties may impair the Company's ability to attract, retain and motivate personnel, and could cause customers, suppliers and others that deal with the Company to seek to change existing business relationships with the Company. If employees depart, the Company's business could be harmed. In addition, the Merger Agreement restricts the Company, without the consent of CenterPoint, from taking specified actions until the Merger is completed or the Merger Agreement terminates. These restrictions may prevent the Company from pursuing otherwise attractive business opportunities and making other changes to the Company's business.

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

31.1	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer
31.2	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer
32	Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002
101	Interactive Data File.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

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

	VECTREN UTILITY HOLDINGS, INC. Registrant
November 13, 2018	/s/ M. Susan Hardwick M. Susan Hardwick Executive Vice President and Chief Financial Officer (Signing on behalf of the registrant and as Principal Accounting & Financial Officer)

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