VECTREN CORP
Form 10-Q
November 03, 2017

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, 2017

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

For the transition period from __________________ to __________________

Commission file number: 1-15467

VECTREN CORPORATION
(Exact name of registrant as specified in its charter)

INDIANA	35-2086905
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ý Yes 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 ý Accelerated filer o
Non-accelerated filer o (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	83,002,391	October 31, 2017
Class	Number of Shares	Date

Access to Information

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

Mailing Address: 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	OUCC: Indiana Office of the Utility Consumer Counselor
FERC: Federal Energy Regulatory Commission	PHMSA: Pipeline and Hazardous Materials Safety Administration
GAAP: Generally Accepted Accounting Principles	PUCO: Public Utilities Commission of Ohio

GCA: Gas Cost Adjustment

IDEM: Indiana Department of Environmental Management

XBRL: eXtensible Business Reporting Language

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash & cash equivalents	$ 8.7	$ 68.6
Accounts receivable - less reserves of $4.7 & $6.0, respectively	253.5	225.3
Accrued unbilled revenues	134.2	172.4
Inventories	131.0	129.9
Recoverable fuel & natural gas costs	29.9	29.9
Prepayments & other current assets	56.2	52.7
Total current assets	613.5	678.8
Utility Plant		
Original cost	6,899.1	6,545.4
Less: accumulated depreciation & amortization	2,697.5	2,562.5
Net utility plant	4,201.6	3,982.9
Investments in unconsolidated affiliates	19.9	20.4
Other utility & corporate investments	42.6	34.1
Other nonutility investments	15.4	16.1
Nonutility plant - net	461.6	423.9
Goodwill	293.5	293.5
Regulatory assets	377.3	308.8
Other assets	36.4	42.2
TOTAL ASSETS	$ 6,061.8	$ 5,800.7

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

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

	September 30, 2017	December 31, 2016
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 259.0	$ 302.2
Accrued liabilities	212.2	207.7
Short-term borrowings	225.9	194.4
Current maturities of long-term debt	175.0	124.1
Total current liabilities	872.1	828.4
Long-term Debt - Net of Current Maturities	1,639.1	1,589.9
Deferred Credits & Other Liabilities		
Deferred income taxes	985.5	905.7
Regulatory liabilities	476.3	453.7
Deferred credits & other liabilities	265.4	254.9
Total deferred credits & other liabilities	1,727.2	1,614.3
Commitments & Contingencies (Notes 7, 9-12)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 83.0 & 82.9, respectively	734.8	729.8
Retained earnings	1,089.9	1,039.6
Accumulated other comprehensive (loss)	(1.3)	(1.3)
Total common shareholders' equity	1,823.4	1,768.1
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$ 6,061.8	$ 5,800.7

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
OPERATING REVENUES				
Gas utility	$120.4	$117.7	$557.2	$530.8
Electric utility	159.2	173.5	433.0	463.3
Nonutility	411.6	339.8	956.1	755.3
Total operating revenues	691.2	631.0	1,946.3	1,749.4
OPERATING EXPENSES				
Cost of gas sold	23.9	29.1	174.0	174.6
Cost of fuel & purchased power	44.1	50.9	128.8	140.3
Cost of nonutility revenues	136.2	110.5	318.4	248.7
Other operating	296.5	256.3	795.2	686.9
Depreciation & amortization	69.5	65.4	205.7	193.4
Taxes other than income taxes	13.5	13.3	42.5	44.8
Total operating expenses	583.7	525.5	1,664.6	1,488.7
OPERATING INCOME	107.5	105.5	281.7	260.7
OTHER INCOME				
Equity in (losses) of unconsolidated affiliates	(0.2)	(0.1)	(1.0)	(0.2)
Other income – net	8.9	7.6	25.1	22.0
Total other income	8.7	7.5	24.1	21.8
INTEREST EXPENSE	22.2	20.9	64.9	64.3
INCOME BEFORE INCOME TAXES	94.0	92.1	240.9	218.2
INCOME TAXES	32.1	30.7	86.1	76.2
NET INCOME AND COMPREHENSIVE INCOME	$61.9	$61.4	$154.8	$142.0
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	83.0	82.8	83.0	82.8
DILUTED COMMON SHARES OUTSTANDING	83.1	82.8	83.0	82.8
BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK	$0.75	$0.74	$1.87	$1.71
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.42	$0.40	$1.26	$1.20

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

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

	Nine Months Ended September 30,	
	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$154.8	$142.0
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	205.7	193.4
Deferred income taxes & investment tax credits	76.6	68.9
Provision for uncollectible accounts	4.0	5.3
Expense portion of pension & postretirement benefit cost	4.4	2.9
Other non-cash items - net	4.1	2.2
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	3.6	42.3
Inventories	(1.1)	(3.6)
Recoverable/refundable fuel & natural gas costs	—	(30.8)
Prepayments & other current assets	(3.1)	15.0
Accounts payable, including to affiliated companies	(54.3)	(7.9)
Accrued liabilities	4.9	1.2
Unconsolidated affiliate dividends	0.1	0.2
Employer contributions to pension & postretirement plans	(3.5)	(18.6)
Changes in noncurrent assets	(28.0)	(32.0)
Changes in noncurrent liabilities	(7.7)	(2.2)
Net cash provided by operating activities	360.5	378.3
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	99.2	—
Dividend reinvestment plan & other common stock issuances	4.6	4.6
Requirements for:		
Dividends on common stock	(104.5)	(99.4)
Retirement of long-term debt	—	(73.0)
Net change in short-term borrowings	31.5	116.7
Net cash used in financing activities	30.8	(51.1)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from sale of assets and other collections	4.8	16.6
Requirements for:		
Capital expenditures, excluding AFUDC equity	(453.5)	(381.9)
Other costs	(3.4)	(4.7)
Changes in restricted cash	0.9	2.5
Net cash used in investing activities	(451.2)	(367.5)
Net change in cash & cash equivalents	(59.9)	(40.3)
Cash & cash equivalents at beginning of period	68.6	74.7
Cash & cash equivalents at end of period	$8.7	$34.4

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

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VECTREN CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings or VUHI), serves as the intermediate holding company for three 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). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005. Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 592,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 145,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 318,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Enterprises also has other legacy businesses that have investments in energy-related opportunities and services and other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

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, 2016, filed with the Securities and Exchange Commission on February 23, 2017, on Form 10-K. Because of the seasonal nature of the Company's operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

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3. Earnings Per Share

The Company uses the two-class method to calculate earnings per share (EPS). The two-class method is an earnings allocation formula that treats a participating security as having rights to earnings that otherwise would have been available to common shareholders. Under the two-class method, earnings for a period are allocated between common shareholders and participating security holders based on their respective rights to receive dividends as if all undistributed book earnings for the period were distributed. The amount of net income attributable to participating securities is immaterial.

Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of share-based compensation to the extent the effect is dilutive.

The following table illustrates the basic and dilutive EPS calculations for the periods presented in these financial statements.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2017	2016	2017	2016
Numerator:				
Reported net income (Numerator for Basic and Diluted EPS)	$ 61.9	$ 61.4	$ 154.8	$ 142.0
Denominator:				
Weighted-average common shares outstanding (Denominator for Basic EPS)	83.0	82.8	83.0	82.8
Conversion of share-based compensation arrangements	0.1	—	0.0	—
Adjusted weighted-average shares outstanding and assumed conversions outstanding (Denominator for Diluted EPS)	83.1	82.8	83.0	82.8
Basic and Diluted EPS	$ 0.75	$ 0.74	$ 1.87	$ 1.71

For the three and nine months ended September 30, 2017 and 2016, all share-based compensation was dilutive and immaterial.

4. Excise & 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 $5.3 million in both the three months ended September 30, 2017 and 2016, as a component of operating revenues. During each of the nine months ended September 30, 2017 and 2016, these taxes totaled $20.2 million. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Retirement Plans & Other Postretirement Benefits

The Company maintains three closed qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP are aggregated under the heading "Pension Benefits." The postretirement benefit plan is presented under the heading “Other Benefits.”

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost follows and the amortizations shown below are primarily reflected in Regulatory assets as a majority of pension and other postretirement benefits are being recovered through rates.

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2017	2016	2017	2016
Service cost	$1.6	$1.8	$0.1	$0.1
Interest cost	3.4	3.6	0.4	0.4
Expected return on plan assets	(5.3)	(5.7)	—	—
Amortization of prior service cost	0.1	0.1	(0.6)	(0.7)
Amortization of actuarial loss	1.9	1.8	—	—
Settlement charge	—	—	—	—
Net periodic cost (benefit)	$1.7	$1.6	$(0.1)	$(0.2)

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2017	2016	2017	2016
Service cost	$4.8	$5.3	$0.2	$0.2
Interest cost	10.3	10.9	1.2	1.3
Expected return on plan assets	(15.8)	(17.1)	—	—
Amortization of prior service cost	0.3	0.3	(1.8)	(2.2)
Amortization of actuarial loss	5.6	5.4	—	—
Settlement charge	1.9	—	—	—
Net periodic cost (benefit)	$7.1	$4.8	$(0.4)	$(0.7)

Lump Sum Settlements

The Company's defined benefit pension plans allow participants to elect a lump sum withdrawal of benefits. Such elections have been made in all plans by plan participants in 2016 and 2017. In one plan, the significance of the lump sum distributions required a remeasurement of that plan's obligation as of June 30, 2017, pursuant to generally accepted accounting principles. As a result, the Company recognized a $1.9 million pension settlement charge in the nine month period ended September 30, 2017.

The Company remeasured the pension obligation for that plan using a discount rate of 3.86 percent at June 30, 2017, compared to the discount rate used at December 31, 2016 of 4.07 percent. The net effect of the discount rate decrease and lump sum payments during the year to date period decreased the pension obligation by $1.5 million upon remeasurement. Of that amount, the majority was recorded as a decrease to Regulatory Assets, as the Company's retirement costs primarily relate to its regulated utilities.

Employer Contributions to Qualified Pension Plans

Currently, the Company does not anticipate making contributions to its qualified pension plans in 2017.

6. Supplemental Cash Flow Information

As of September 30, 2017 and December 31, 2016, the Company has accruals related to utility and nonutility plant purchases totaling approximately $41.2 million and $30.0 million, respectively.

7. Investment in ProLiance Holdings, LLC

The Company has an investment in ProLiance Holdings, LLC (ProLiance), an affiliate of the Company and Citizens Energy Group (Citizens). Much of the Proliance business was sold on June 18, 2013 when ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). Consistent with its ownership percentage, the Company is allocated 61 percent of ProLiance’s profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

The Company's remaining investment at September 30, 2017, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows.

(In millions)	As of September 30, 2017
Cash	$ 0.9
Investment in LA Storage	22.5
Other midstream asset investment	5.7
Total investment in ProLiance	$ 29.1
Included in:	
Investments in unconsolidated affiliates	$ 19.0
Other nonutility investments	$ 10.1

LA Storage, LLC Storage Asset Investment
ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with a 25 percent interest, which it accounts for using the equity method. The project, which includes a pipeline system, is expected to include 12-19 Bcf of storage capacity, and has the potential for further expansion. This pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and can connect area liquefied natural gas regasification terminals to an interstate natural gas transmission system and storage facilities.

Approximately 12 Bcf of the storage, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to further develop the caverns. The timing and extent of development of these caverns and pipeline system is dependent on market conditions, including pricing, need for storage and transmission capacity, and development of the liquefied natural gas market, among other factors. To date, development activity has been modest due to the current low demand for storage facilities. The FERC development permit expired on June 3, 2017. As anticipated, SEI did not renew the permit but has the option to refile an application in the future. The development of the storage market and related pricing are critical assumptions in the analysis of the recoverability of the investment's carrying value. As of September 30, 2017 and December 31, 2016, ProLiance's investment in the joint venture was $36.9 million and $36.7 million, respectively.

8. Financing Activities

Utility Holdings and Vectren Capital Short-Term Borrowing Facilities

On July 14, 2017, Utility Holdings closed on a credit agreement with a group of lenders providing for a credit facility of revolving commitments in the aggregate amount of $400 million with a $10 million swing line sublimit and a $20 million letter of credit sublimit. The Utility Holdings credit agreement is jointly and severally guaranteed by its wholly owned subsidiaries Indiana Gas, SIGECO, and VEDO and is a backup facility for Utility Holdings commercial paper program. Additionally, on July 14, 2017, Vectren Capital Corporation, a wholly owned subsidiary of the Company, closed on a credit agreement with the same group of lenders providing a credit facility of revolving commitments in the aggregate amount of $200 million with a $40 million swing line sublimit and a $80 million letter of credit sublimit. The Vectren Capital credit agreement funds the short-term borrowing needs of the Company's corporate and nonutility operations and is guaranteed by Vectren Corporation.

These credit agreements mature on July 14, 2022 and replaced bank credit agreements that had an original maturity date of October 31, 2019. The total $600 million of short-term borrowing capacity between the two lines remains unchanged; however, the Utility Holdings credit agreement commitment was increased by $50 million as compared to the prior credit agreement, and the Vectren Capital credit agreement commitment was decreased by $50 million as compared to the prior credit agreement.

Utility Holdings Long-Term Debt Issuance
On July 14, 2017, Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors agreed to purchase the following tranches of notes: (i) $100 million of 3.26% Guaranteed Senior Notes, Series A, due August 28, 2032 and (ii) $100 million of 3.93% Guaranteed Senior Notes, Series B, due November 29, 2047.

The Series A note proceeds were received on August 28, 2017. The notes are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO, wholly owned subsidiaries of Utility Holdings. Subject to the satisfaction of customary conditions precedent, the Series B proceeds will be received on November 29, 2017.

SIGECO Variable Rate Tax-Exempt Bonds
On September 14, 2017, the Company, through SIGECO, executed a Bond Purchase and Covenants Agreement (Purchase and Covenants Agreement) providing SIGECO ability to remarket and/or refinance approximately $152 million of tax-exempt bonds at a variable rate based on one month LIBOR through May 1, 2023 (except for one bond that matures on January 1, 2022).

Bonds remarketed through the Bond Purchase and Covenants Agreement included three issuances that were mandatorily tendered to the Company on September 14, 2017. These were

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

Through the Purchase and Covenants Agreement, on September 22, 2017 SIGECO also extended the mandatory tender date of its variable rate 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025. (The original tender date was September 24, 2019).

The Purchase and Covenants Agreement provides the option, subject to satisfaction of customary conditions precedent, for the lenders to purchase from SIGECO and for SIGECO to convert to a variable rate other currently outstanding fixed rate, tax-exempt bonds that are callable in March 2018 (2013 Series A Notes totaling $22.2 million due March 1, 2038) and May 2018 (2013 Series B Notes totaling $39.6 million due by May 1, 2043).

In October 2017, SIGECO executed forward starting interest rate swaps providing that on January 1, 2020 interest rates on the 2013 Series A, B, and E Notes will convert to a 2.4 percent fixed interest rate 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 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.

9. Commitments & Contingencies

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, such as Energy Systems Group, LLC (ESG), a subsidiary of the Energy Services operating segment, issue payment and performance bonds and other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors and subcontractors, and support warranty obligations.

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Specific to ESG's role as a general contractor in the performance contracting industry, at September 30, 2017, there are 60 open surety bonds supporting future performance. The average face amount of these obligations is $9.6 million, and the largest obligation has a face amount of $75.9 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various contractors. At September 30, 2017, approximately 30 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented as the Company assesses the likelihood of loss as remote. Since inception, ESG has paid a de minimis amount on energy savings guarantees.

Corporate Guarantees & Other Support
The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At September 30, 2017, parent level guarantees support a maximum of $345 million of ESG’s performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Given the infrequent occurrence of any performance shortfalls historically on any of these commitments, no reserve for a potential liability has been deemed warranted.

Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. Under this agreement, all payment obligations to Keenan are also guaranteed by the Company. The Company guarantee of the Keenan operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments but assesses the likelihood of loss as remote based on, primarily, the nature of the project.

The Company has not been called on to perform under these guarantees historically. While there can be no assurance that performance under these provisions will not be required in the future, the Company believes the likelihood of a material amount being incurred under these provisions is remote given the nature of the projects, the manner in which the savings estimates are developed, and the fact that the value of the guarantees decrease over time as actual energy savings are achieved by the customer.

The Company, from time to time, and primarily through Vectren Capital, issues letters of credit that support consolidated operations. At September 30, 2017, letters of credit outstanding total $31.3 million.

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.

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

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 include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last 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 no 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.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At September 30, 2017 and December 31, 2016, the Company has regulatory assets totaling $22.7 million and $21.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed below.

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 two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, 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.

In March 2016, the IURC issued an Order re-approving approximately $890 million of the Company's gas infrastructure modernization projects requested in the third update of the Plan, and approving the inclusion in rates of actual investments made through June 30, 2015. While most of the proposed capital spend has been approved as proposed, approximately $80 million of future projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, the

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Company proposed to add a new project to its Plan pursuant to Senate Bill 560 totaling approximately $65 million. The project, which consists of a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area, as well as allows the Company to further diversify its gas supply portfolio via access to shale gas in the Marcellus and Utica reserves, was excluded for recovery under the Plan. The IURC stated because the project was not in the original plan filed in 2013, it does not qualify for cost recovery under Senate Bill 560. In the Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. On April 27, 2017, the Indiana Court of Appeals affirmed the IURC Order. The Company does not expect similar issues related to updating future plan filings as the project inclusion process is now better understood by all parties.

Subsequent to the March 2016 Order, the Company has received three additional Orders approving plan investments. On June 29, 2016, the IURC issued an Order approving the inclusion in rates of investments made from July 2015 to December 2015. On January 25, 2017 the IURC issued an Order (January 2017 Order) approving the inclusion in rates of investments made from January 2016 to June 2016. The January 2017 Order also approved the Company's plan update, which is now $950 million through 2020. The plan increase of $60 million is due to additional investment related to pipeline safety and compliance requirements under Senate Bill 251. On July 26, 2017 the IURC issued an Order (July 2017 Order) approving the inclusion in rates of investments made from July 2016 to December 2016. Through the July 2017 Order, approximately $407 million of the approved capital investment plan has been incurred and included for recovery.

In October 2017, the Company submitted its seventh semi-annual filing, seeking approval of the recovery in rates of investments made through June 30, 2017, and updates to the seven-year capital investment plan that includes projects recovered under Senate Bill 560 and Senate Bill 251. The updated plan reflects capital expenditures of approximately $995 million, an increase of $45 million for additional investments related to pipeline safety and compliance requirements under Senate Bill 251. The Company expects an order in this proceeding in early 2018.

At September 30, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $68.3 million and $51.1 million, respectively.

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 total, the Company has made capital investments on projects that are now in-service under the DRR totaling $294.3 million as of September 30, 2017, of which $261.1 million has been approved for recovery under the DRR through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $29.5 million and $24.4 million at September 30, 2017 and December 31, 2016, respectively. In August 2017, the Company

received approval to adjust the DRR rates, effective September 1, 2017, for recovery of costs incurred through December 31, 2016.

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. At September 30, 2017 and December 31, 2016, the Company has regulatory assets totaling $59.6 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of September 30, 2017, the Company's deferrals have not reached this bill impact cap. On May 1, 2017, 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.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, the Company anticipates it will file a general rate case for the inclusion in rate base of the above costs in early 2018.

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 particular 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 2018 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.

In December 2016, PHMSA issued 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. The Company believes that the cost to comply with these new rules would be considered federally mandated. On August 3, 2017, the Company filed for authority to recover the associated costs using the mechanism allowed under Senate Bill 251. The request includes approximately $15 million of operating expenses and $17 million of capital investments over a four-year period beginning in 2018. The Company expects an IURC order no later than the first quarter of 2018. The Company does not have storage operations in Ohio.

Additionally, PHMSA finalized a rule on excess flow valves, which went into effect in April 2017. At the customer's request, in Indiana and Ohio, excess flow valves will be installed at the customer's cost.

11. Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560
The provisions of Senate Bill 560, as described in the Gas Rate & Regulatory Matters footnote 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. The filing requested the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017.

On September 20, 2017, the IURC issued an Order approving the settlement agreement reached between the Company, the OUCC and a coalition of industrial customers on May 18, 2017. The settlement agreement reduces the plan spend to $446 million, with defined annual caps on recoverable capital investments. The majority of the reduction relating to the removal of 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. In removing it from the plan, the request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which will be filed by the end of 2023. 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 also addresses that semi-annual filings are to be made August 1, based on capital investments and expenses through the period ended April 30, and February 1, based on capital investments and expenses through October 31. The parties agreed in the settlement that the Company would make its first semi-annual filing on August 1, 2017, with additional time allotted subsequent to the plan case order for intervening parties to review the filing and to address any changes to the settlement agreement.

On August 1, 2017, the Company filed with the IURC its initial request for approval of the revenue requirement associated with capital investment through April 30, 2017. Once approved, this filing will initiate the 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. Through April 30, 2017, the Company has invested approximately $7 million under the plan. The Company expects an order by the end of 2017.

Renewable Generation Resources
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 Integrated Resource Plan (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. See more information on the IRP below in Environmental & Sustainability Matters. The cost of the projects is estimated to be approximately $16 million.

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 September 30, 2017, $30 million has been spent 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. These costs will be included for recovery no later than the next rate case. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of September 30, 2017, the Company has approximately $11.6 million deferred related to depreciation and operating expenses, and $4.2 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.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January 2015 Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV. On June 22, 2016, the IURC issued an Order granting the Company a CPCN for the NOV required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Indiana Court of Appeals affirmed the IURC's June 22, 2016 Order.

SIGECO Electric Demand Side Management (DSM) Program Filing

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

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performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the nine months ended September 30, 2017 and 2016, the Company recognized electric utility revenue of $8.7 million and $8.2 million, respectively, associated with this lost margin recovery mechanism.

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, most of the Company's eligible industrial customers 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 now limits 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 recent 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 has been remanded to the IURC for further proceedings to determine the reasonableness of the Company's entire energy efficiency plan. On June 13, 2017, the Company filed additional testimony supporting the plan. In response to the proposals to cap lost margin recovery, the Company has filed supplemental testimony that supports lost margin recovery based on the average measure life of the plan, estimated at nine years. Testimony of intervening parties was filed on July 26, 2017, and these parties continue to oppose the reasonableness of the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. The Company expects an order by the end of 2017.

On April 10, 2017, the Company submitted its request for approval 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. Intervening parties continue to oppose the reasonableness of the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. An order is expected by the end of 2017.

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, 2017, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $134.3 million at September 30, 2017.

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. The Company will continue to monitor this proceeding and evaluate any potential impacts on the Company's complaint cases but would not expect them to be material.

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. As detailed further below and in the next corporate sustainability report, the Company continues to establish its plans that involve upgrades to and diversification of its generation portfolio. 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 latest sustainability report, which received core level certification from the Global Reporting Initiative.

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 (discussion in Note 10), Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Integrated Resource Planning Process

As required by Indiana regulation, the Company completed its 2016 Integrated Resource Plan (IRP) and submitted it to 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 report. A draft of that report was issued on July 28, 2017. The Company has taken the comments provided in the draft report into consideration as it works to finalize its generation resource plans. The final IRP report is expected by the end of 2017, and is not expected to change the 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. The Company continues to work on finalizing the generation portfolio transition plan, evaluating all elements in order to ensure we arrive at the best solution for all stakeholders, especially its customers. The Company plans to submit a regulatory filing for a Certificate of Need, including construction timelines and costs of new generation resources, as well as necessary unit retrofits, in the first quarter of 2018 to begin the generation transition process. In that filing, the Company will seek approval of its generation plan, including timely recovery of all federally mandated compliance costs, as well as the authority to defer the cost of new generation until the time of its next rate case.
Currently, the Company operates approximately 1,000 MW of coal-fired generation, 245 MW of natural gas peaking units, and 3 MW via a landfill-gas-to-electricity facility. The Company also has 80 MW of wind power through two long-term power purchase agreements and 32 MW of coal generation through its ownership in OVEC. The Company's 2016 IRP preferred portfolio illustrates a future less reliant on coal. The twenty-year plan reflects the retirement of a portion of the Company's current coal-fired fleet, transitions a significant portion of generation to natural gas and includes new renewable energy sources, specifically universal solar. The detailed plan introduces approximately 54 MW of universal solar installed by 2019. The plan included the Company exiting its joint operations of Warrick Unit 4, a 300 MW unit shared with Alcoa, by 2020. The Company would complete upgrades to its existing coal-fired F.B. Culley Unit 3, a 270-megawatt unit, to comply with federal water regulations specific to the Effluent Limitations Guidelines (ELG) around 2023 in order to keep the unit in operation. As discussed in more detail in the ELG section below, the EPA has administratively stayed the compliance deadlines in the ELG rule pending reconsideration. In 2024, the IRP points to the retirement of coal-fired A.B. Brown plant Units 1 & 2 along with F.B. Culley Unit 2, collectively representing 580 MW. This generation would be replaced by a newly constructed combined cycle natural gas plant, with the capability of producing approximately 890 MW by 2024. In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the short-term uncertainties related to ELG implementation are not expected to have a significant impact on the Company's long term preferred generation plan.

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 strategy, and the expected exit at the end of 2023 is consistent with its IRP which reflects having completed all planned unit retirements and bringing new resources online by that date.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. 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 rather than citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings. In August, 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. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect.

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.

Throughout 2016 and 2017, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $35 million to $130 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 preferred IRP. 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, 2017, the Company had recorded an approximate $30 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $35 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.

Effluent Limitation Guidelines (ELGs)

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs 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 ELGs 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 ELGs 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.

The current 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 ELGs, which were approved by IDEM. For plants identified in the Company's preferred 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 within one year of issuance of the renewal of its intent to retire the unit. 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.

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. The EPA has also sought a stay of the current judicial review litigation in federal district court. The court has yet to grant the indefinite stay sought by EPA, and instead placed the parties on a periodic status update schedule. 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 administrative stay of 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 partial stay of the ELG implementation deadlines does not impact its preferred generation plan as modeled in the IRP because the final compliance deadline of December 31, 2023 is still in place.

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. 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 that 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. The EPA was expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2017; however, in a March filing challenging the new standard, the EPA filed a request to stay the litigation pending a potential review of the ozone standard by the agency, but on August 2, 2017, EPA reversed course and announced it would not delay implementation of the rule. While the future of the current ozone standard is not certain, it is possible counties in southwest Indiana could be declared in non-attainment with the current ozone standard, and thus could have an effect on future economic development activities in the Company's service territory. The Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In September 2016, the EPA finalized a supplement to the Cross State Air Pollution Rule (CSAPR) that requires further NOx reductions during the ozone season (May - September). The Company is in full compliance with these NOx reduction requirements through its current investment in SCR technology.

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

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). In March 2017, the EPA withdrew a Federal Implementation Plan (FIP) as a compliance option. Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb CO_2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. 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. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA has 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, on October 10, 2017, EPA announced it would be publishing a proposal to repeal the CPP. EPA intends to take comment on whether it should repeal the entire CPP, as it has determined it cannot repeal portions of the rule. EPA has indicated it will not be taking comment on its possible replacement at this time, although it is likely that in the future EPA will propose a more limited replacement that seeks to require emission reductions that can be achieved at the facility. Repeal without replacement of the CPP could create potential litigation risk arising from the absence of direct federal regulation in this area that courts have previously determined preempt common law nuisance claims.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. The Company’s share of total tons of CO_2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2016, the Company has achieved a reduction in emissions of CO_2 of 43 percent (on a tonnage basis). The Company has been able to achieve these reductions through the retirement of F.B. Culley Unit 1, expiration of municipal wholesale power contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by fluctuations in generation, coal burn reductions and energy efficiency programs, the Company's emissions of CO_2 can vary year to year. As such, the three-year average emission reduction for the period 2014 to 2016 is 35 percent from 2005 levels. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and a landfill gas investment. With respect to the CO_2 emission rate, since 2005 through 2016, the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1,967 lbs CO_2/MWh to 1,922 lbs CO_2/MWh, for a reduction of 3 percent. The Company’s CO_2 emission rate of 1,922 lbs CO_2/MWh is basically the same as Indiana's average CO_2 emission rate of 1,923 lbs CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions.

However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

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 can not petition to withdraw until November 2019. As previously noted, since 2005 through 2016, the Company has achieved reduced emissions of CO_2 by 43 percent (on a tonnage basis). While the litigation and 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 $44.2 million ($23.9 million at Indiana Gas and $20.3 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 $15.6 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, 2017 and December 31, 2016, approximately $2.6 million and $2.9 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

13. Impact of Recently Issued Accounting Principles

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. 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 improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Company plans to adopt the guidance under the modified retrospective method.

In July 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016.

The Company is in the process of finalizing its assessment of all revenue streams for the standard’s impact on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures and has identified all material revenue streams. The Company continues to monitor and assess utility and construction industry specific issues and wait for final resolution of these outstanding issues in order to determine the standard's impact. Management does not believe adoption of the standard will have a significant impact on the Company's pattern of revenue recognition but the implementation of the standard may result in changes to processes and controls. The Company will adopt the guidance effective January 1, 2018, and record a cumulative effect adjustment to retained earnings at the adoption date.

Leases
In February 2016, the FASB issued new accounting guidance 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, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements and will adopt the guidance effective January 1, 2019.

Stock Compensation
In March 2016, the FASB issued new accounting guidance intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU was effective for annual periods beginning after December 15, 2016, and interim periods therein. Most of the Company's share-based awards are settled via cash payments and were therefore not impacted by this standard. The Company's adoption of this standard did not have a material impact on the financial statements.

Presentation of Net Periodic Pension and Postretirement Benefit Costs
In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension and postretirement benefit costs. This ASU is effective for annual periods beginning after December 15, 2017, and relevant interim periods. This ASU requires the Company to report the service cost component in the same line items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of income from operations. Capitalization of net benefit cost is limited to only the service cost component of benefit costs, when applicable.

The ASU requires retrospective presentation of the service and non-service costs components in the income statement and prospective application regarding the capitalization of only the service cost component of net benefit costs. The Company is finalizing its assessment of the standard and does not anticipate its adoption to have a significant impact on the financial statements. The Company will adopt the guidance effective January 1, 2018.

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.

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14. 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, 2017		December 31, 2016	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,814.1	$1,947.9	$1,714.0	$1,835.8
Short-term borrowings	225.9	225.9	194.4	194.4
Cash & cash equivalents	8.7	8.7	68.6	68.6
Natural gas purchase instrument assets (1)	0.2	0.2	—	—
Natural gas purchase instrument liabilities (2)	3.3	3.3	—	—
Restricted cash	—	—	0.9	0.9

(1) Presented in "Other utility & corporate investments" on the Condensed Consolidated Balance Sheets (unaudited).
(2) Presented in "Deferred credits & other liabilities" on the Condensed Consolidated Balance Sheets (unaudited).

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

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

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue. 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.

Because of the nature of certain other investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At September 30, 2017 and December 31, 2016, the fair value for these financial instruments was not estimated. The carrying value of these investments at September 30, 2017 and December 31, 2016 was $15.4 million and $16.1 million, respectively.

15. Segment Reporting

The Company segregates its operations into three groups: 1) Utility Group, 2) Nonutility Group, and 3) Corporate and Other.

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

The Nonutility Group reports the following segments: Infrastructure Services, Energy Services, and Other Businesses. The Infrastructure Services segment, through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provides underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. Fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services totaled $46.5 million and $36.3 million for the three months ended September 30, 2017 and 2016, respectively, and for the nine months ended September 30, 2017 and 2016 totaled $123.9 million and $93.1 million, respectively. Energy Services, through the wholly owned subsidiary Energy Systems Group, LLC, provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects.

In 2016, the estimated depreciable lives for certain pieces of equipment at Minnesota Limited, LLC were reevaluated and extended due to a change in service life of the equipment. As a result of this evaluation, the Company extended the estimated useful life of certain pieces of equipment effective January 1, 2016. The effect of this change in estimate was an anticipated reduction of annual depreciation expense of approximately $9.6 million in 2016.

Corporate and Other includes unallocated corporate expenses such as advertising and certain charitable contributions, among other activities, that benefit the Company’s other operating segments. Net income is the measure of profitability used by management for all operations.

Information related to the Company's reportable segments is summarized as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
(In millions)	2017	2016	2017	2016
Revenues				
Utility Group				
Gas Utility Services	$120.4	$117.7	$557.2	$530.8
Electric Utility Services	159.2	173.5	433.0	463.3
Other Operations	11.4	10.5	34.2	31.6
Eliminations	(11.3)	(10.4)	(34.0)	(31.4)
Total Utility Group	279.7	291.3	990.4	994.3
Nonutility Group				
Infrastructure Services	339.9	263.8	764.7	565.6
Energy Services	72.5	76.6	193.2	191.8
Total Nonutility Group	412.4	340.4	957.9	757.4
Corporate & Other Group	0.1	0.2	0.4	0.5
Eliminations	(1.0)	(0.9)	(2.4)	(2.8)
Consolidated Revenues	$691.2	$631.0	$1,946.3	$1,749.4
Profitability Measure - Net Income				
Utility Group Net Income				
Gas Utility Services	$1.0	$0.9	$55.8	$46.0
Electric Utility Services	27.2	31.3	56.8	67.0
Other Operations	2.6	2.7	9.6	9.3
Utility Group Net Income	30.8	34.9	122.2	122.3
Nonutility Group Net Income (Loss)				
Infrastructure Services	26.6	18.2	28.6	9.8
Energy Services	4.9	6.2	4.9	8.7
Other Businesses	(0.2)	(0.1)	(0.5)	(0.3)
Nonutility Group Net Income	31.3	24.3	33.0	18.2
Corporate & Other Group Net Income (Loss)	(0.2)	2.2	(0.4)	1.5
Consolidated Net Income	$61.9	$61.4	$154.8	$142.0

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

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings or VUHI), serves as the intermediate holding company for three 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). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005. Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 592,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 145,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 318,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Enterprises has other legacy businesses that have investments in energy-related opportunities and services, among other investments. All of the above is collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services.

The Company has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company's SEC filings. The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company's 2016 annual report filed on Form 10-K.

Executive Summary of Consolidated Results of Operations

In this discussion and analysis, the Company analyzes contributions to consolidated earnings and earnings per share from its Utility Group and Nonutility Group separately. Because each group operates independently and offers different energy-related products and services, the analysis separately addresses the opportunities and risks that arise from each group's distinct competencies and business strategies.

The Utility Group generates revenue primarily from the delivery of natural gas and electric service to its customers. The primary source of cash flow for the Utility Group results from the collection of customer bills and payment for goods and services procured for the delivery of gas and electric services. The Company segregates its regulated utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The activities of, and revenues and cash flows generated by, the Nonutility Group are closely linked to the utility industry, and the results of those operations are generally impacted by factors similar to those impacting the overall utility industry. In addition, there are other operations, referred to herein as Corporate and Other, that include unallocated corporate expenses such as advertising and certain charitable contributions, among other activities.

Results for the three months ended September 30, 2017 were earnings of $61.9 million, or $0.75 per share, compared to earnings of $61.4 million, or $0.74 per share for the three months ended September 30, 2016. For the nine months ended September, 30, 2017, consolidated net income was $154.8 million or $1.87 per share, compared to $142.0 million or $1.71 per share for the nine months ended September 30, 2016.

Consolidated Results

Net income (loss) and earnings per share, in total and by group, for the three and nine months ended September 30, 2017 and 2016 follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2017	2016	2017	2016
Net income (loss)	$61.9	$61.4	$154.8	$142.0
Attributed to:				
Utility Group	30.8	34.9	122.2	122.3
Nonutility Group	31.3	24.3	33.0	18.2
Corporate & other	(0.2)	2.2	(0.4)	1.5
Basic EPS	$0.75	$0.74	$1.87	$1.71
Attributed to:				
Utility Group	0.37	0.42	1.47	1.48
Nonutility Group	0.38	0.29	0.40	0.22
Corporate & other	—	0.03	—	0.01

Utility Group

In the third quarter of 2017, the Utility Group earnings were $30.8 million, compared to $34.9 million in 2016. In the nine months ended September 30, 2017, the Utility Group earned $122.2 million, compared to $122.3 million in 2016. Utility group results for the quarter and year to date periods reflect increased earnings from the returns on continued investment in the gas infrastructure replacement programs in Indiana and Ohio. Results also reflect the expected decrease in usage of a large electric customer that completed its transition to a co-generation facility, lower electric margins as both cooling and heating degree days in 2017 were lower when compared to 2016, and higher performance-based compensation expense primarily driven by an increase in the Company's stock price.

Nonutility Group

The Nonutility group results for the third quarter of 2017 were earnings of $31.3 million, compared to earnings of $24.3 million in the prior year. For the nine months ended September 30, 2017, the Nonutility Group reported earnings of $33.0 million, compared to earnings of $18.2 million in the prior year period. Both the quarter and year to date periods reflect favorable results compared to 2016, driven by Infrastructure Services' transmission operations in both periods, and distribution operations in the year to date period. Results reflect record third quarter and year to date revenues driven by the continued execution of work on the large pipeline project in Ohio and other pipeline projects, along with distribution services and other growth. Results for Energy Services were lower in both the quarter and year to date periods. Both periods reflect the expiration of Section 179D on December 31, 2016, which allowed for federal tax deductions related to achieved energy efficiency savings, and increased operating costs related to growth in the sales and development functions.

Dividends

Dividends declared for the three months ended September 30, 2017, were $0.42 per share, compared to $0.40 per share for the same period in 2016. Dividends declared for the nine months ended September 30, 2017, were $1.26 per share, compared to $1.20 per share for the same period in 2016.

Use of Non-GAAP Performance Measures and Per Share Measures

Contribution to Vectren's Basic EPS

Per share earnings contributions of the Utility Group, Nonutility Group, and Corporate and Other are presented and are non-GAAP measures. Such per share amounts are based on the earnings contribution of each group included in the Company’s consolidated results divided by the Company’s basic average shares outstanding during the period. The earnings per share of the groups do not represent a direct legal interest in the assets and liabilities allocated to the groups; instead they represent a direct equity interest in the Company's assets and liabilities as a whole. These non-GAAP measures are used by management to evaluate the performance of individual businesses. In addition, other items giving rise to period over period variances, such as weather, may be presented on an after tax and per share basis. These amounts are calculated at a statutory tax rate divided by the Company’s basic average shares outstanding during the period. Accordingly, management believes these measures are useful to investors in understanding each business’ contribution to consolidated earnings per share and in analyzing consolidated period to period changes and the potential for earnings per share contributions in future periods. Per share amounts of the Utility Group and the Nonutility Group are reconciled to the GAAP financial measure of basic EPS by combining the two. Any resulting differences are attributable to results from Corporate and Other operations. The non-GAAP financial measures disclosed by the Company should not be considered a substitute for, or superior to, financial measures calculated in accordance with GAAP, and the financial results calculated in accordance with GAAP.

Detailed Discussion of Results of Operations

Following is a more detailed discussion of the results of operations of the Company’s Utility and Nonutility operations. The detailed results of operations for these groups are presented and analyzed before the reclassification and elimination of certain intersegment transactions necessary to consolidate those results into the Company’s Condensed Consolidated Statements of Income.

Results of Operations of the Utility Group

The Utility Group is composed of Utility Holdings’ operations, which consists of the Company’s regulated utility operations and other operations that provide information technology and other support services to those regulated operations. Regulated operations consist of a natural gas distribution business and an electric transmission and distribution business. The natural gas distribution business provides natural gas distribution and transportation services to nearly two-thirds of Indiana and about 20 percent of Ohio, primarily in the west-central area. The electric transmission and distribution business provides electric distribution services primarily to southwestern Indiana, and its power generating and wholesale power operations. In total, these regulated operations supply natural gas and/or electricity to over one million customers. Utility Group operating results net of certain intersegment eliminations and reclassifications for the three and nine months ended September 30, 2017 and 2016, follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2017	2016	2017	2016
OPERATING REVENUES				
Gas utility	$120.4	$117.7	$557.2	$530.8
Electric utility	159.2	173.5	433.0	463.3
Other	0.1	0.1	0.2	0.2
Total operating revenues	279.7	291.3	990.4	994.3
OPERATING EXPENSES				
Cost of gas sold	23.9	29.1	174.0	174.6
Cost of fuel & purchased power	44.1	50.9	128.8	140.3
Other operating	82.1	79.4	252.1	250.8
Depreciation & amortization	59.0	55.2	174.3	162.8
Taxes other than income taxes	12.6	12.7	40.1	42.9
Total operating expenses	221.7	227.3	769.3	771.4
OPERATING INCOME	58.0	64.0	221.1	222.9
OTHER INCOME - NET	8.2	6.7	23.1	20.1
INTEREST EXPENSE	18.3	17.2	53.5	52.2
INCOME BEFORE INCOME TAXES	47.9	53.5	190.7	190.8
INCOME TAXES	17.1	18.6	68.5	68.5
NET INCOME	$30.8	$34.9	$122.2	$122.3
CONTRIBUTION TO VECTREN BASIC EPS	$0.37	$0.42	$1.47	$1.48

Utility Group Margin

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

In addition, the Company separately reflects regulatory expense recovery mechanisms within Gas utility margin and Electric utility margin. These amounts represent dollar-for-dollar recovery of other operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas Utility Margin

Gas Utility margin and throughput by customer type follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2017	2016	2017	2016
Gas utility revenues	$120.4	$117.7	$557.2	$530.8
Cost of gas sold	23.9	29.1	174.0	174.6
Total gas utility margin	$96.5	$88.6	$383.2	$356.2
Margin attributed to:				
Residential & commercial customers	$72.4	$67.1	$293.1	$272.3
Industrial customers	15.9	14.2	53.1	47.3
Other	1.5	1.4	6.4	5.7
Regulatory expense recovery mechanisms	6.7	5.9	30.6	30.9
Total gas utility margin	$96.5	$88.6	$383.2	$356.2
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	6.0	5.9	59.3	65.2
Industrial customers	25.4	28.0	87.2	93.8
Total sold & transported volumes	31.4	33.9	146.5	159.0

Gas utility margins were $96.5 million and $383.2 million for the three and nine months ended September 30, 2017, and compared to 2016, increased $7.9 million quarter over quarter and $27.0 million year over year. Gas utility margins increased $7.1 million in the quarter and $27.3 million year over year when excluding margin from regulatory expense recovery mechanisms, which increased $0.8 million quarter over quarter and decreased $0.3 million year over year. Gas margin was favorably impacted by increased returns on infrastructure replacement programs in Indiana and Ohio of $5.5 million quarter over quarter and $20.9 million year over year, increases in large customer margin of $1.2 million quarter over quarter and $4.1 million year over year primarily due to a new customer in the second half of 2016, and increases associated with small customer count growth of $0.3 million quarter over quarter and $1.9 million year over year. With rate designs that substantially limit the impact of weather on small customer margin, the warmer than normal weather in the first quarter of 2017 decreased sold and transported volumes, but had only a slight unfavorable impact on small customer margin compared to 2016. Heating degree days were 89 percent of normal in Ohio and 80 percent of normal in Indiana in the first nine months of 2017, compared to 97 percent of normal in Ohio and 90 percent of normal in Indiana in the same period in 2016.

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

Electric Utility Margin and volumes sold by customer type follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2017	2016	2017	2016
Electric utility revenues	$159.2	$173.5	$433.0	$463.3
Cost of fuel & purchased power	44.1	50.9	128.8	140.3
Total electric utility margin	$115.1	$122.6	$304.2	$323.0
Margin attributed to:				
Residential & commercial customers	$76.4	$79.4	$197.0	$202.8
Industrial customers	26.4	30.5	73.2	84.8
Other	0.9	0.4	2.8	2.6
Regulatory expense recovery mechanisms	3.3	4.6	8.1	11.6
Subtotal: retail	$107.0	$114.9	$281.1	$301.8
Wholesale power & transmission system margin	8.1	7.7	23.1	21.2
Total electric utility margin	$115.1	$122.6	$304.2	$323.0
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	796.5	830.0	2,042.8	2,122.6
Industrial customers	587.8	755.6	1,600.7	2,110.0
Other customers	5.1	5.2	16.0	16.6
Total retail volumes sold	1,389.4	1,590.8	3,659.5	4,249.2

Retail

Electric retail utility margins were $107.0 million and $281.1 million for the three and nine months ended September 30, 2017, and compared to 2016, decreased by $7.9 million quarter over quarter and $20.7 million year over year. Results reflect a decrease in large customer margin of $4.1 million quarter over quarter and $11.6 million year to date, primarily due to the completion by a large customer of its transition to a co-generation (cogen) facility resulting in lower usage of approximately 155 GWh quarter over quarter and 490 GWh year to date. Electric margin, which is not protected by weather normalizing mechanisms, reflects a $4.5 million decrease in customer margin in the quarter as annualized cooling degree days were normal compared to 115 percent of normal in 2016. For the year to date period, electric results reflect a $6.3 million decrease in customer margin related to weather as annualized heating degree days were 80 percent of normal compared to 90 percent of normal in 2016 and annualized cooling degree days were 108 percent of normal compared to 119 percent of normal in 2016. Margin from regulatory expense recovery mechanisms decreased $1.3 million quarter over quarter and $3.5 million year to date.

As previously discussed, SABIC Innovative Plastics (SABIC), a large industrial utility customer of the Company, announced on December 3, 2013, its plan to build a cogen facility in order to generate power to meet a significant portion of its ongoing power needs. Electric service was provided to SABIC by the Company under a long-term contract that expired on May 2, 2016. At that date, SABIC became a tariff customer. The cogen facility was operational as of January 1, 2017 and provides approximately 85 MW of capacity. The Company continues to provide all of SABIC's power requirements above the approximate 85 MW capacity of the cogen, as well as backup power under approved tariff rates.

Margin from Wholesale Electric Activities

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2017	2016	2017	2016
MISO Transmission system margin	$ 7.4	$ 7.7	$ 20.0	$ 19.5
MISO Off-system margin	0.7	—	3.1	1.7
Total wholesale margin	$ 8.1	$ 7.7	$ 23.1	$ 21.2

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $7.4 million and $7.7 million during the three months ended September 30, 2017 and 2016, respectively. Transmission system margin was $20.0 million and $19.5 million during the nine months ended September 30, 2017 and 2016, respectively. As of September 30, 2017, the Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $134.3 million at September 30, 2017. 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, including while under construction.

In the third quarter of 2017, margin from off system sales was $0.7 million compared to break-even in 2016. For the nine months ended September 30, 2017, margin from off-system sales was $3.1 million compared to $1.7 million in 2016. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year is shared equally with customers. Results for the periods presented are net of sharing, and reflect higher market prices due to higher natural gas prices and lower system load due to the transition of SABIC to cogen.

Utility Group Operating Expenses

Other Operating

During the third quarter of 2017, other operating expenses were $82.1 million, an increase of $2.7 million, compared to the third quarter of 2016. For the nine months ended September 30, 2017, other operating expenses were $252.1 million, an increase of $1.3 million, compared to 2016. Excluding costs recovered directly in margin, other operating expenses increased $3.3 million quarter over quarter and increased $5.3 million year over year, when compared to 2016. Both quarter and year to date periods reflect increases in performance-based compensation costs driven by changes in the Company's stock price.

Depreciation & Amortization

In the third quarter of 2017, depreciation and amortization expense was $59.0 million, compared to $55.2 million in 2016. For the nine months ended September 30, 2017, depreciation and amortization expense was $174.3 million, which represents an increase of $11.5 million compared to 2016. 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 $12.6 million and $12.7 million for the third quarter of 2017 and 2016, respectively. Year to date, taxes other than income taxes were $40.1 million, compared to $42.9 million in 2016. The reduction in taxes other than income taxes in the year to date period of 2017 compared to 2016 was primarily related to lower property taxes.

Other Income - Net

Other income-net reflects income of $8.2 million for the third quarter of 2017, an increase of $1.5 million, compared to 2016. Year to date, other income-net reflects income of $23.1 million, compared to $20.1 million in 2016. 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 include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last 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 no 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.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received Orders in 2008 and 2007 associated with the most recent base rate cases. These Orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Orders provide for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $20 million annually at Indiana Gas and $3 million annually at SIGECO. The debt-related post-in-service carrying costs are currently recognized in the Consolidated Statements of Income. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At September 30, 2017 and December 31, 2016, the Company has regulatory assets totaling $22.7 million and $21.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed below.

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 two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, 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.

In March 2016, the IURC issued an Order re-approving approximately $890 million of the Company’s gas infrastructure modernization projects requested in the third update of the Plan, and approving the inclusion in rates of actual investments made through June 30, 2015. While most of the proposed capital spend has been approved as proposed, approximately $80 million of future projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, the Company proposed to add a new project to its Plan pursuant to Senate Bill 560 totaling approximately $65 million. The project, which consists of a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area, as well as allows the Company to further diversify its gas supply portfolio via access to shale gas in the Marcellus and Utica reserves, was excluded for recovery under the Plan. The IURC stated because the project was not in the original plan filed in 2013, it does not qualify for cost recovery under Senate Bill 560. In the Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. On April 27, 2017, the Indiana Court of Appeals affirmed the IURC Order. The Company does not expect similar issues related to updating future plan filings as the project inclusion process is now better understood by all parties.

Subsequent to the March 2016 Order, the Company has received three additional Orders approving plan investments. On June 29, 2016, the IURC issued an Order approving the inclusion in rates of investments made from July 2015 to December 2015. On January 25, 2017 the IURC issued an Order (January 2017 Order) approving the inclusion in rates of investments made from January 2016 to June 2016. The January 2017 Order also approved the Company's plan update, which is now $950 million through 2020. The plan increase of $60 million is due to additional investment related to pipeline safety and compliance requirements under Senate Bill 251. On July 26, 2017 the IURC issued an Order (July 2017 Order) approving the inclusion in rates of investments made from July 2016 to December 2016. Through the July 2017 Order, approximately $407 million of the approved capital investment plan has been incurred and included for recovery.

In October 2017, the Company submitted its seventh semi-annual filing, seeking approval of the recovery in rates of investments made through June 30, 2017, and updates to the seven-year capital investment plan that includes projects recovered under Senate Bill 560 and Senate Bill 251. The updated plan reflects capital expenditures of approximately $995 million, an increase of $45 million for additional investments related to pipeline safety and compliance requirements under Senate Bill 251. The Company expects an order in this proceeding in early 2018.

At September 30, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $68.3 million and $51.1 million, respectively.

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 total, the Company has made capital investments on projects that are now in-service under the DRR totaling $294.3 million as of September 30, 2017, of which $261.1 million has been approved for recovery under the DRR through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $29.5 million and $24.4 million at September 30, 2017 and December 31, 2016, respectively. In August 2017, the Company received approval to adjust the DRR rates, effective September 1, 2017, for recovery of costs incurred through December 31, 2016.

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. At September 30, 2017 and December 31, 2016, the Company has regulatory assets totaling $59.6 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of September 30, 2017, the Company's deferrals have not reached this bill impact cap. On May 1, 2017, 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.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, the Company anticipates it will file a general rate case for the inclusion in rate base of the above costs in early 2018.

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 particular 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 2018 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.

In December 2016, PHMSA issued 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. The Company believes that the cost to comply with these new rules would be considered federally mandated. On August 3, 2017, the Company filed for authority to recover the associated costs using the mechanism allowed under Senate Bill 251. The request includes approximately $15 million of operating expenses and $17 million of capital investments over a four-year period beginning in 2018. The Company expects an IURC order no later than the first quarter of 2018. The Company does not have storage operations in Ohio.

Additionally, PHMSA finalized a rule on excess flow valves, which went into effect in April 2017. At the customer's request, in Indiana and Ohio, excess flow valves will be installed at the customer's cost.

Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560

The provisions of Senate Bill 560, as described in the Gas Rate & Regulatory Matters footnote 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. The filing requested the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017.

On September 20, 2017, the IURC issued an Order approving the settlement agreement, reached between the Company, the OUCC and a coalition of industrial customers on May 18, 2017. The settlement agreement reduces the plan spend to $446 million, with defined annual caps on recoverable capital investments. The majority of the reduction relating to the removal of 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. In removing it from the plan, the request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which will be filed by the end of 2023. 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 also addresses that semi-annual filings are to be made August 1, based on capital investments and expenses through the period ended April 30, and February 1, based on capital investments and expenses through October 31. The parties agreed in the settlement that the Company would make its first semi-annual filing on August 1, 2017, with additional time allotted subsequent to the plan case order for intervening parties to review the filing and to address any changes to the settlement agreement.

On August 1, 2017, the Company filed with the IURC its initial request for approval of the revenue requirement associated with capital investment through April 30, 2017. Once approved, this filing will initiate the 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. Through April 30, 2017, the Company has invested approximately $7 million under the plan. The Company expects an order by the end of 2017.

Renewable Generation Resources
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 Integrated Resource Plan (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. See more information on the IRP below in Environmental & Sustainability Matters. The cost of the projects is estimated to be approximately $16 million.

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 September 30, 2017, $30 million has been spent 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. These costs will be included for recovery no later than the next rate case. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of September 30, 2017, the Company has approximately $11.6 million deferred related to depreciation and operating expenses, and $4.2 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.

In June 2015, Joint Appellants' Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., and Valley Watch, Inc. (the appellants) challenged the IURC's January 2015 Order. On October 29, 2015, the Indiana Court of Appeals issued an opinion that affirmed the IURC's findings with regard to equipment required to comply with MATS and certain national pollutant discharge elimination system rules but remanded the case to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV. On

June 22, 2016, the IURC issued an Order granting the Company a CPCN for the NOV required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order challenging the findings made by the IURC. On February 14, 2017, the Indiana Court of Appeals affirmed the IURC's June 22, 2016 Order.

SIGECO Electric Demand Side Management (DSM) Program Filing
On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the Company's electric service territory that complied with the IURC’s energy saving targets. Consistent with the Company’s proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the nine months ended September 30, 2017 and 2016, the Company recognized electric utility revenue of $8.7 million and $8.2 million, respectively, associated with this lost margin recovery mechanism.

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, most of the Company’s eligible industrial customers 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 now limits 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 recent 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 has been remanded to the IURC for further proceedings to determine the reasonableness of the Company's entire energy efficiency plan. On June 13, 2017, the Company filed additional testimony supporting the plan. In response to the proposals to cap lost margin recovery, the Company has filed supplemental testimony that supports lost margin recovery based on the average measure life of the plan, estimated at nine years. Testimony of intervening parties was filed on July 26, 2017, and these parties continue to oppose the reasonableness of the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. The Company expects an order by the end of 2017.

On April 10, 2017, the Company submitted its request for approval 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. Intervening parties continue to oppose the reasonableness of the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. An order is expected by the end of 2017.

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, 2017, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $134.3 million at September 30, 2017.

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. The Company will continue to monitor this proceeding and evaluate any potential impacts on the Company's complaint cases but would not expect them to be material.

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. As detailed further below and in the next corporate sustainability report, the Company continues to establish its plans, that involve upgrades to and diversification of its generation portfolio. 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 latest sustainability report, at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

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.

Integrated Resource Planning Process

As required by Indiana regulation, the Company completed its 2016 Integrated Resource Plan (IRP) and submitted it to 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 report. A draft of that report was issued on July 28, 2017. The Company has taken the comments provided in the draft report into consideration as it works to finalize its generation resource plans. The final IRP report is expected by the end of 2017, and is not expected to change the 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. The Company continues to work on finalizing the generation portfolio transition plan, evaluating all elements in order to ensure we arrive at the best solution for all stakeholders, especially its customers. The Company plans to submit a regulatory filing for a Certificate of Need, including construction timelines and costs of new generation resources, as well as necessary unit retrofits, in the first quarter of 2018 to begin the generation transition process. In that filing, the Company will seek approval of its generation plan, including timely recovery of all federally mandated compliance costs, as well as the authority to defer the cost of new generation until the time of its next rate case.

Currently, the Company operates approximately 1,000 MW of coal-fired generation, 245 MW of natural gas peaking units, and 3 MW via a landfill-gas-to-electricity facility. The Company also has 80 MW of wind power through two long-term power purchase agreements and 32 MW of coal generation through its ownership in OVEC. The Company’s 2016 IRP preferred portfolio illustrates a future less reliant on coal. The twenty-year plan reflects the retirement of a portion of the Company’s current coal-fired fleet, transitions a significant portion of generation to natural gas and includes new renewable energy sources, specifically universal solar. The detailed plan introduces approximately 54 MW of universal solar installed by 2019. The plan included the Company exiting its joint operations of Warrick Unit 4, a 300 MW unit shared with Alcoa, by 2020. The Company would complete upgrades to its existing coal-fired F.B. Culley Unit 3, a 270-megawatt unit, to comply with federal water regulations specific to the Effluent Limitations Guidelines (ELG) around 2023 in order to keep the unit in operation. As discussed in more detail in the ELG section below, the EPA has administratively stayed the compliance deadlines in the ELG rule pending reconsideration. In 2024, the IRP points to the retirement of coal-fired A.B. Brown plant Units 1 & 2 along with F.B. Culley Unit 2, collectively representing 580 MW. This generation would be replaced by a newly constructed combined cycle natural gas plant, with the capability of producing approximately 890 MW by 2024. In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the short-term uncertainties related to ELG implementation are not expected to have a significant impact on the Company’s long term preferred generation plan.

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 strategy, and the expected exit at the end of 2023 is consistent with its IRP which reflects having completed all planned unit retirements and bringing new resources online by that date.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. 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 rather than citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings. In August, 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.

While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect.

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.

Throughout 2016 and 2017, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $35 million to $130 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 preferred IRP. 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, 2017, the Company had recorded an approximate $30 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $35 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.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing electric generation facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs 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 ELGs 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 ELGs 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.

The current 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 ELGs, which were approved by IDEM. For plants identified in the Company’s preferred 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 within one year of issuance of the renewal of its intent to retire the unit. 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.

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. The EPA has also sought a stay of the current judicial review litigation in federal district court. The court has yet to grant the indefinite stay sought by EPA, and instead placed the parties on a periodic status update schedule. 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 administrative stay of 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 partial stay of the ELG implementation deadlines does not impact its preferred generation plan as modeled in the IRP because the final compliance deadline of December 31, 2023 is still in place.

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. 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 that 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. The EPA was expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2017; however, in a March filing challenging the new standard, the EPA filed a request to stay the litigation pending a potential review of the ozone standard by the agency, but on August 2, 2017, EPA reversed course and announced it would not delay implementation of the rule. While the future of the current ozone standard is not certain, it is possible counties in southwest Indiana could be declared in non-attainment with the current ozone standard, and thus could have an effect on future economic development activities in the Company's service territory. The Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In September 2016, the EPA finalized a supplement to the Cross State Air Pollution Rule (CSAPR) that requires further NOx reductions during the ozone season (May - September). The Company is in full compliance with these NOx reduction requirements through its current investment in SCR technology.

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

Vectren remains committed to responsible environmental stewardship and conservation efforts. The preferred IRP, as submitted to the IURC in December 2016, 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. The preferred IRP would result in a 60 percent reduction in carbon emissions from 2005 to 2024 and assumed the CPP, as described below, was in place beginning in 2024. While the ultimate fate of the CPP regulation is uncertain given the legal challenges it faces and recent proposal to repeal the CPP which, if finalized, would also invariably result in yet more litigation, the Company has prepared the IRP as a long-term plan that performs well in both high and low regulatory environments.

Ultimately if a national climate change policy is implemented, the Company believes it should have the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to 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.

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GGRT) maintained by the EPA, the Company’s direct CO_2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA’s e-GGRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions

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

- Since 2005 and through 2016, the Company has achieved a reduction in emissions of CO_2 of 43 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 2014 to 2016 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 received Core level certification by the Global Reporting Initiative and demonstrates the Company's commitment to sustainability and transparency in operations. The Company's latest 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;
- Developing renewable energy and energy efficiency performance contracting projects through its Energy Services segment; and

- Helping energy producers install pipes that allow for more natural gas power generation and reduced gas flaring as well as serving distribution integrity management programs that reduce methane leaks, through its Infrastructure Services segment.

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb CO_2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the initial deadline of September 2016 to submit a final state implementation plan (SIP). In March 2017, the EPA withdrew a Federal Implementation Plan (FIP) as a compliance option. Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb CO_2/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. 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. Among other things, the stay delays the requirement to submit a final SIP by the original September 2016 deadline and could extend implementation to 2024. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA has 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, on October 10, 2017, EPA announced it would be publishing a proposal to repeal the CPP. EPA intends to take comment on whether it should repeal the entire CPP, as it has determined it cannot repeal portions of the rule. EPA has indicated it will not be taking comment on its possible replacement at this time, although it is likely that in the future EPA will propose a more limited replacement that seeks to require emission reductions that can be achieved at the facility. Repeal without replacement of the CPP could create potential litigation risk arising from the absence of direct federal regulation in this area that courts have previously determined preempt common law nuisance claims.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. The Company's share of total tons of CO_2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005 through 2016, the Company has achieved a reduction in emissions of CO_2 of 43 percent (on a tonnage basis). The Company has been able to achieve these reductions through the retirement of F.B. Culley Unit 1, expiration of municipal wholesale power contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. Since emissions are further impacted by fluctuations in generation, coal burn reductions and energy efficiency programs, the Company's emissions of CO_2 can vary year to year. As such, the three-year average emission reduction for the period 2014 to 2016 is 35 percent from 2005 levels. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and a landfill gas investment. With respect to the CO_2 emission rate, since 2005 through 2016, the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1,967 lbs CO_2/MWh to 1,922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1,922 lbs CO_2/MWh is basically the same as Indiana's average CO_2 emission rate of 1,923 lbs CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown
At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if

a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

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 can not petition to withdraw until November 2019. As previously noted, since 2005 through 2016, the Company has achieved reduced emissions of CO2 by 43 percent (on a tonnage basis). While the litigation and 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 $44.2 million ($23.9 million at Indiana Gas and $20.3 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 $15.6 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, 2017 and December 31, 2016, approximately $2.6 million and $2.9 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Results of Operations of the Nonutility Group

The Nonutility Group operates in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Enterprises has other legacy businesses that have investments in energy-related opportunities and services, among other investments. All of the above is collectively referred to as the Nonutility Group.

The Nonutility Group results were earnings of $31.3 million and $33.0 million for the three and nine months ended September 30, 2017, respectively, compared to earnings of $24.3 million and $18.2 million for the three and nine months ended September 30, 2016.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share amounts)	2017	2016	2017	2016
NET INCOME (LOSS)	$31.3	$24.3	$33.0	$18.2
CONTRIBUTION TO VECTREN BASIC EPS	$0.38	$0.29	$0.40	$0.22
NET INCOME (LOSS) ATTRIBUTED TO:				
Infrastructure Services	$26.6	$18.2	$28.6	$9.8
Energy Services	4.9	6.2	4.9	8.7
Other Businesses	(0.2)	(0.1)	(0.5)	(0.3)

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC. Inclusive of holding company costs, results for Infrastructure Services' operations for the third quarter of 2017 were earnings of $26.6 million, compared to earnings of $18.2 million for the same period in the prior year. During the nine months ended September 30, 2017, Infrastructure Services earned $28.6 million, compared to $9.8 million year to date in 2016. Total Infrastructure Services revenues in the third quarter of 2017 were a record $339.9 million compared to revenues of $263.8 million in the third quarter of 2016, driven largely by the Ohio pipeline project. Year to date, 2017 revenues totaled $764.7 million, compared to $565.6 million for the year to date period in 2016. At September 30, 2017, Infrastructure Services had an estimated backlog of blanket contracts of $530 million and bid contracts of $225 million, for a total backlog of $755 million. This compares to an estimated backlog at September 30, 2016 of $635 million.

The distribution portion of the business is performing well as gas utilities across the country continue to make significant investments in their infrastructure systems. Along with strong customer demand for construction services from gas utilities, the warm and dry weather in the first nine months of the year resulted in record year to date earnings and revenues for this portion of the business.

Results for the transmission portion of the business have significantly improved for the quarter and year to date periods and were driven by the continued execution of work related to the large transmission pipeline project in Ohio as well as other pipeline projects. Both 2016 and year to date 2017 results reflect strong performance from large pipeline projects. Though the timing and recurrence of these large projects is less predictable, they demonstrate expertise in this area and provide strong revenues. Infrastructure Services' is positioned well to do this work, but the focus remains on the recurring integrity, station, and maintenance work. While the focus remains on the recurring work, opportunities for large transmission pipeline construction projects will continue to be pursued. The fundamental business model related to the long cycle of integrity, station, and maintenance work in the transmission sector remains unchanged. Demand remains high due to aging infrastructure and evolving safety and reliability regulations.

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects through its wholly owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' operations were earnings of $4.9 million during the third quarter of 2017, compared to earnings of $6.2 million during the third quarter of 2016. For the nine months ended September 30, 2017, earnings were $4.9 million, compared to earnings of $8.7 million in 2016. The lower results are primarily driven by earnings in 2016 of $1.3 million in the quarter and $2.7 million in the year-to-date period from Section 179D, which allowed for federal tax deductions related to achieved energy efficiency savings. Section 179D expired on December 31, 2016. In addition, increased operating costs related to growth in the sales and development functions also contributed to the lower 2017 results. Energy Services had year-to-date revenues of $193.2 million in 2017, compared to revenues of $191.8 million for the year-to-date period in 2016.

At September 30, 2017, the backlog of signed fixed price contracts was $179 million compared to $182 million at September 30, 2016. The sales funnel continues to grow, now at a record $473 million, reflective of strong demand for Energy Services’ work.

The Company's long-term view of the performance contracting and sustainable infrastructure opportunities remains strong with continued national focus expected on energy conservation and sustainability, renewable energy, and security as power prices across the country rise and customer focus on new, efficient, clean sources of energy grows.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. 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 improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Company plans to adopt the guidance under the modified retrospective method.

In July 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016.

The Company is in the process of finalizing its assessment of all revenue streams for the standard’s impact on the Consolidated Balance Sheets, Consolidated Statements of Operations, and disclosures and has identified all material revenue streams. The Company continues to monitor and assess utility and construction industry specific issues and wait for final resolution of these outstanding issues in order to determine the standard's impact. Management does not believe adoption of the standard will have a significant impact on the Company's pattern of revenue recognition but the implementation of the standard may result in changes to processes and controls. The Company will adopt the guidance effective January 1, 2018, and record a cumulative effect adjustment to retained earnings at the adoption date.

Leases
In February 2016, the FASB issued new accounting guidance 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, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements and will adopt the guidance effective January 1, 2019.

Stock Compensation
In March 2016, the FASB issued new accounting guidance intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU was effective for annual periods beginning after December 15, 2016, and interim periods therein. Most of the Company's share-based awards are settled via cash payments and were therefore not impacted by this standard. The Company's adoption of this standard did not have a material impact on the financial statements.

Presentation of Net Periodic Pension and Postretirement Benefit Costs

In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension and postretirement benefit costs. This ASU is effective for annual periods beginning after December 15, 2017, and relevant interim periods. This ASU requires the Company to report the service cost component in the same line items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of income from operations. Capitalization of net benefit cost is limited to only the service cost component of benefit costs, when applicable.

The ASU requires retrospective presentation of the service and non-service costs components in the income statement and prospective application regarding the capitalization of only the service cost component of net benefit costs. The Company is finalizing its assessment of the standard and does not anticipate its adoption to have a significant impact on the financial statements. The Company will adopt the guidance effective January 1, 2018.

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

Within the Company’s consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corporation (Vectren Capital) funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital’s debt, but does not guarantee Utility Holdings’ debt. Vectren Capital’s long-term debt, including current maturities, outstanding at September 30, 2017 approximated $334 million. Vectren Capital's short-term obligations outstanding at September 30, 2017 approximated $14 million. Utility Holdings’ outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities SIGECO, Indiana Gas, and VEDO. Utility Holdings’ long-term debt, including current maturities, and short-term obligations outstanding at September 30, 2017 approximated $1,096 million and $212 million, respectively. Additionally, prior to Utility Holdings’ formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue new tax-exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt outstanding at September 30, 2017 was approximately $384 million.

The Company’s common stock dividends are primarily funded by utility operations. Nonutility operations have demonstrated profitability and the ability to generate cash flows. These cash flows are primarily reinvested in other nonutility investments, but are also used to fund a portion of the Company’s dividends, and from time to time may be reinvested in utility operations or used for corporate expenses.

Vectren Corporation's corporate credit rating is A-, as rated by S&P Global Ratings (S&P Global). Moody's Investor Services (Moody's) does not provide a rating for Vectren Corporation. The credit ratings of the senior unsecured debt of Utility Holdings, SIGECO and Indiana Gas, at September 30, 2017, are A-/A2, as rated by S&P Global and Moody’s, respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings’ commercial paper has a credit rating of A-2/P-1. The current outlook of both S&P Global and Moody’s is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. S&P Global and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

The Company’s consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company’s operations. The Company’s equity to long-term capitalization ratio was 50 percent and 51 percent as of September 30, 2017 and December 31, 2016. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders’ equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of September 30, 2017, 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 debt and equity 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 policies and regulations, growth of the regulated business, and growth of Infrastructure Services and Energy Services. 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 affected.

On July 14, 2017, Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors agreed to purchase the following tranches of notes: (i) $100 million of 3.26% Guaranteed Senior Notes, Series A, due August 28, 2032 and (ii) $100 million of 3.93% Guaranteed Senior Notes, Series B, due November 29, 2047. The notes are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO, wholly owned subsidiaries of Utility Holdings.

The Series A note proceeds were received on August 28, 2017. Subject to the satisfaction of customary conditions precedent, the Series B proceeds will be received on November 29, 2017.

On September 14, 2017, the Company, through SIGECO, executed a Bond Purchase and Covenants Agreement (Purchase and Covenants Agreement) providing SIGECO ability to remarket and/or refinance approximately $152 million of tax-exempt bonds at a variable rate based on one month LIBOR through May 1, 2023 (except for one bond that matures on January 1, 2022).

Bonds remarketed through the Bond Purchase and Covenants Agreement included three issuances that were mandatorily tendered to the Company on September 14, 2017. These were
- 2013 Series C Notes with a principal of $4.6 million and a final maturity date of January 1, 2022;
- 2013 Series D Notes with a principal of $22.5 million and a final maturity date of March 1, 2024; and
- 2013 Series E Notes with a principal of $22.0 million and final maturity date of May 1, 2037.

Through the Purchase and Covenants Agreement, on September 22, 2017 SIGECO also extended the mandatory tender date of its variable rate 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025. (The original tender date was September 24, 2019).

The Purchase and Covenants Agreement provides the option, subject to satisfaction of customary conditions precedent, for the lenders to purchase from SIGECO and for SIGECO to convert to a variable rate other currently outstanding fixed rate, tax-exempt bonds that are callable in March 2018 (2013 Series A Notes totaling $22.2 million due March 1, 2038) and May 2018 (2013 Series B Notes totaling $39.6 million due by May 1, 2043).

In October 2017, SIGECO executed forward starting interest rate swaps providing that on January 1, 2020 interest rates on the 2013 Series A, B, and E Notes will convert to a 2.4 percent fixed interest rate 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 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 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. On June 21, 2017 an Order for long-term financing authority of $70 million of long-term debt and $65 million of equity financing was received from the PUCO for VEDO and expires in June 2018. On February 22, 2017, orders for long-term financing authority of $160 million and $200 million of long-term debt, and $120 million and $180 million of equity financing, were received from the IURC for SIGECO and Indiana Gas, respectively. These orders expire in March 2019.

Consolidated Short-Term Borrowing Arrangements

At September 30, 2017, the Company had $600 million of short-term borrowing capacity, including $400 million for the Utility Group and $200 million for the wholly owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $188 million was available for the Utility Group operations and $186 million was available for the wholly owned Nonutility Group and corporate operations. The Company's short-term credit facilities were renewed on July 14, 2017 and mature on July 14, 2022.

The Company has historically funded the short-term borrowing needs of Utility Holdings’ operations through the commercial paper market but maintains the ability to use the Utility Holdings' short-term borrowing facility when necessary. Following is certain information regarding the short-term borrowing arrangements outstanding at September 30, 2017.

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2017	2016	2017	2016
As of September 30				
Balance Outstanding	$211.7	$131.2	$14.2	$—
Weighted Average Interest Rate	1.39%	0.67%	2.33%	N/A
Nine Months Ended September 30 Average				
Balance Outstanding	$161.6	$28.2	$11.1	$0.3
Weighted Average Interest Rate	1.22%	0.62%	2.37%	1.60%
Maximum Month End Balance Outstanding	$238.7	$131.2	$35.3	$6.3

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2017	2016	2017	2016
Quarterly Average - September 30				
Balance Outstanding	$210.9	$73.8	$28.2	$—
Weighted Average Interest Rate	1.41%	0.63%	2.38%	N/A
Maximum Month End Balance Outstanding	$238.7	$131.2	$28.5	$—

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan and other employee benefit plan requirements. New issuances provided additional liquidity of $4.6 million for the nine months ended September 30, 2017 and September 30, 2016.

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. The PATH Act allows for 50 percent bonus depreciation for property placed in service in 2015 - 2017; 40 percent in 2018; and 30 percent in 2019. Including the impact of alternative minimum tax credits that will be utilized in future periods, the extension of 50 percent bonus depreciation is expected to result in an approximate $55 million positive impact to cash flows for the 2017 tax year. Potential tax reform may impact bonus depreciation in future periods.

Potential Uses of Liquidity

Pension Funding Obligations

For the nine months ended September 30, 2017, the Company did not contribute to its qualified pension plans. Currently, the Company does not anticipate making contributions to its qualified pension plans in 2017.

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, such as Energy Systems Group, LLC (ESG), a subsidiary of the Energy Services operating segment, issue payment and performance bonds and other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors and subcontractors, and support warranty obligations.

Specific to ESG's role as a general contractor in the performance contracting industry, at September 30, 2017, there are 60 open surety bonds supporting future performance. The average face amount of these obligations is $9.6 million, and the largest obligation has a face amount of $75.9 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various contractors. At September 30, 2017, approximately 30 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented as the Company assesses the likelihood of loss as remote. Since inception, ESG has paid a de minimis amount on energy savings guarantees.

Corporate Guarantees & Other Support

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At September 30, 2017, parent level guarantees support a maximum of $345.3 million of ESG’s performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees. Given the infrequent occurrence of any performance shortfalls historically on any of these commitments, no reserve for a potential liability has been deemed warranted.

Further, an energy facility operated by ESG and managed by Keenan Ft. Detrick Energy, LLC (Keenan), is governed by an operations agreement. Under this agreement, all payment obligations to Keenan are also guaranteed by the Company. The Company guarantee of the Keenan operations agreement does not state a maximum guarantee. Due to the nature of work performed under this contract, the Company cannot estimate a maximum potential amount of future payments but assesses the likelihood of loss as remote based on, primarily, the nature of the project.

The Company has not been called on to perform under these guarantees historically. While there can be no assurance that performance under these provisions will not be required in the future, the Company believes the likelihood of a material amount being incurred under these provisions is remote given the nature of the projects, the manner in which the savings estimates are developed, and the fact that the value of the guarantees decrease over time as actual energy savings are achieved by the customer.

The Company, from time to time, and primarily through Vectren Capital, issues letters of credit that support consolidated operations. At September 30, 2017, letters of credit outstanding total $31.3 million.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at approximately $152 million for the remainder of 2017. Nonutility capital expenditures are estimated at approximately $6.3 million for the remainder of 2017.

Contractual Obligations

The Company’s contractual obligations primarily consist of debt issued by SIGECO, Indiana Gas, Utility Holdings, and Vectren Capital; certain plant and nonutility plant purchase commitments, and other long-term liabilities. For the nine months ended September 30, 2017, 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, 2016, 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 capital requirements has been cash generated from operations, which totaled $360.5 million and $378.3 million for the nine months ended September 30, 2017 and 2016, respectively. The decrease in operating cash flow for the nine months ended 2017 compared to 2016 is driven primarily by timing of cash flow related to large projects at the Nonutility Group.

Financing Cash Flow
Net cash flow proceeds from financing activities were $30.8 million during the nine months ended September 30, 2017 compared to requirements of $51.1 million in 2016. Financing activity in both periods presented reflects the payment of dividends. The increase in cash flow proceeds from financing activities was primarily related to there being no retirements of long-term debt in 2017, compared to retirements of $73 million in 2016.

Investing Cash Flow
Cash flow required for investing activities was $451.2 million and $367.5 million during the nine months ended September 30, 2017 and 2016, respectively. The increase in investing activity in 2017 primarily reflects higher capital expenditures for the Utility Group.

Forward-Looking Information

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

- Factors affecting utility operations such as 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, physical attacks, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations,

financial condition, results of operations, and reputation.

- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as 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

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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 surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, and other nonutility products and services; 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; higher operating expenses; and reductions in the value of investments.
- 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.
- The performance of projects undertaken by the Company's nonutility businesses and the success of efforts to realize value from, invest in and develop new opportunities, including but not limited to, the Company's Infrastructure Services, Energy Services, and remaining ProLiance Holdings assets.
- Factors affecting Infrastructure Services, including the level of success in bidding contracts; fluctuations in volume and mix of contracted work; mix of projects received under blanket contracts; unanticipated cost increases in completion of the contracted work; funding requirements associated with multiemployer pension and benefit plans; changes in legislation and regulations impacting the industries in which the customers served operate; the effects of weather; failure to properly estimate the cost to construct projects; the ability to attract and retain qualified employees in a fast growing market where skills are critical; cancellation and/or reductions in the scope of projects by customers; credit worthiness of customers; ability to obtain materials and equipment required to perform services; and changing market conditions, including changes in the market prices of oil and natural gas that would affect the demand for infrastructure construction.
- Factors affecting Energy Services, including unanticipated cost increases in completion of the contracted work; changes in legislation and regulations impacting the industries in which the customers served operate; changes in economic influences impacting customers served; failure to properly estimate the cost to construct projects; risks associated with projects owned or operated; failure to appropriately design, construct, or operate projects; the ability to attract and retain qualified employees; cancellation and/or reductions in the scope of projects by customers; changes in the timing of being awarded projects; credit worthiness of customers; lower energy prices negatively impacting the economics of performance contracting business; and changing market conditions.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.

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 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 Vectren 2016 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended September 30, 2017, 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, 2017, 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, 2017, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:
1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II

ITEM 1. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company 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 & sustainability matters, and rate & regulatory matters. The condensed consolidated financial statements are included in Part 1 Item 1.

During the third quarter of 2014, the Company was notified of claims by a group of current and former SIGECO employees (“claimants”) who participated in the Pension Plan for Salaried Employees of SIGECO (“SIGECO Salaried Plan”). That plan was merged into the Vectren Corporation Combined Non-Bargaining Retirement Plan (“Vectren

Combined Plan") effective July 1, 2000. The claims related to the claimants' election for benefits to be calculated under the Vectren Combined Plan's cash-balance formula rather than the SIGECO Salaried Plan formula. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan (Plan) and the Company. The Company denied the allegations set forth in the Complaint and moved to dismiss the case. In April 2016, the court dismissed part of the complaint but allowed the remaining

claims to proceed. On February 6, 2017, the parties reached a settlement in principle to resolve the matter. On August 16, 2017, the court entered an Order and Final Judgment approving settlement of the remaining claims and entered a final
judgment of dismissal. The terms of the settlement did not have a material impact on the Company or the Plan.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company's operating results and financial condition, causing them to be materially adversely affected. The Company's risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2016 Form 10-K and are therefore not presented herein.

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

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company's share-based compensation plans; however, no such open market purchases were made during the quarter ended September 30, 2017.

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

3.1	Code of By-Laws of Vectren corporation as most recently amended as of October 1, 2017 (filed and designated in Form 8-K, dated September 25, 2017, File No. 1-15467, as Exhibit 3.1).
4.1	Note Purchase Agreement, dated July 14, 2017, between Vectren Utility Holdings, Inc. (VUHI), certain subsidiaries of VUHI as guarantors and each of the purchasers named therein. (Filed and designated in Form 8-K dated July 17, 2017 File No. 1-15467, as Exhibit 4.1).
4.2	Bond Purchase and Covenants Agreement, dated September 14, 2017, between Southern Indiana Gas and Electric Company and PNC Bank, National Association. (Filed and designated in Form 8-K dated September 25, 2017, File No 1-5467, as Exhibit 4.).
10.1	Credit Agreement, dated as of July 14, 2017, among Vectren Utility Holdings, Inc., as borrower (VUHI); certain subsidiaries of VUHI, as guarantors; Bank of America, N.A., as administrative agent, swing line lender and a letter of credit issuer; Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K dated July 17, 2017 File No. 1-5467, as Exhibit 10.1).
10.2	Credit Agreement, dated as of July 14, 2017, among Vectren Capital, Corp., as borrower; Vectren Corporation, as guarantor; Bank of America, N.A., as administrative agent, swing line lender and a letter of credit issuer; Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K dated July 17, 2017 File No. 1-5467, as Exhibit 10.2).
10.3	Amendment to Agreement for Unit Four, made effective as of September 21, 2017, by and between Alcoa Power Generating Inc., and Southern Indiana Gas and Electric Company. (Filed and Designated in Form 8-K dated September 25, 2017, File No. 1-15467, as Exhibit 10.1).
31.1	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer
31.2	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer
32	Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002
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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	VECTREN CORPORATION Registrant
November 3, 2017	/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)