VECTREN CORP
Form 10-Q
November 06, 2018

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

FORM 10-Q

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

For the quarterly period ended September 30, 2018

OR
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	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	83,080,695	October 31, 2018
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	XBRL: eXtensible Business Reporting Language
IDEM: Indiana Department of Environmental Management	

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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, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash & cash equivalents	$ 28.8	$ 16.6
Accounts receivable - less reserves of $4.1 & $5.1, respectively	230.5	262.9
Accrued unbilled revenues	156.2	207.1
Inventories	119.4	126.6
Recoverable fuel & natural gas costs	7.8	19.2
Prepayments & other current assets	53.9	47.0
Total current assets	596.6	679.4
Utility Plant		
Original cost	7,394.5	7,015.4
Less: accumulated depreciation & amortization	2,850.9	2,738.7
Net utility plant	4,543.6	4,276.7
Investments in unconsolidated affiliates	1.5	19.7
Other utility & corporate investments	48.6	43.7
Other nonutility investments	9.6	9.6
Nonutility plant - net	483.0	464.1
Goodwill	293.5	293.5
Regulatory assets	469.5	416.8
Other assets	34.6	35.8
TOTAL ASSETS	$ 6,480.5	$ 6,239.3

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, 2018	December 31, 2017
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 232.1	$ 366.2
Accrued liabilities	246.1	222.3
Short-term borrowings	325.3	249.5
Current maturities of long-term debt	60.0	100.0
Total current liabilities	863.5	938.0
Long-term Debt - Net of Current Maturities	1,978.9	1,738.7
Deferred Credits & Other Liabilities		
Deferred income taxes	518.4	491.3
Regulatory liabilities	938.8	937.2
Deferred credits & other liabilities	306.1	284.8
Total deferred credits & other liabilities	1,763.3	1,713.3
Commitments & Contingencies (Notes 8, 11-14)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 83.1 & 83.0, respectively	739.5	736.9
Retained earnings	1,136.6	1,113.7
Accumulated other comprehensive (loss)	(1.3)	(1.3)
Total common shareholders' equity	1,874.8	1,849.3
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$ 6,480.5	$ 6,239.3

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

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,	
	2018	2017	2018	2017
OPERATING REVENUES				
Gas utility	$122.1	$120.4	$600.7	$557.2
Electric utility	160.0	159.2	437.4	433.0
Nonutility	382.9	411.6	929.8	956.1
Total operating revenues	665.0	691.2	1,967.9	1,946.3
OPERATING EXPENSES				
Cost of gas sold	24.5	23.9	211.4	174.0
Cost of fuel & purchased power	47.5	44.1	137.7	128.8
Cost of nonutility revenues	121.4	136.2	299.8	318.4
Other operating	296.2	296.7	809.3	794.2
Merger-related	11.1	—	26.4	—
Depreciation & amortization	73.9	69.5	217.7	205.7
Taxes other than income taxes	14.1	13.5	49.6	42.5
Total operating expenses	588.7	583.9	1,751.9	1,663.6
OPERATING INCOME	76.3	107.3	216.0	282.7
OTHER INCOME				
Equity in (losses) of unconsolidated affiliates	(0.3)	(0.2)	(18.3)	(1.0)
Other income – net	9.6	9.1	28.7	24.1
Total other income	9.3	8.9	10.4	23.1
INTEREST EXPENSE	24.6	22.2	72.1	64.9
INCOME BEFORE INCOME TAXES	61.0	94.0	154.3	240.9
INCOME TAXES	10.6	32.1	18.2	86.1
NET INCOME AND COMPREHENSIVE INCOME	$50.4	$61.9	$136.1	$154.8
WEIGHTED AVERAGE AND DILUTED COMMON SHARES OUTSTANDING	83.1	83.0	83.1	83.0
BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK	$0.61	$0.75	$1.64	$1.87
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.45	$0.42	$1.35	$1.26

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 CASH FLOWS
(Unaudited – In millions)

	Nine Months Ended September 30,	
	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$136.1	$154.8
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	217.7	205.7
Deferred income taxes & investment tax credits	12.6	76.6
Provision for uncollectible accounts	5.3	4.0
Expense portion of pension & postretirement benefit cost	3.3	4.4
Other non-cash items - net	18.3	4.1
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	78.0	3.6
Inventories	7.2	(1.1)
Recoverable/refundable fuel & natural gas costs	11.4	—
Prepayments & other current assets	(6.7)	(3.1)
Accounts payable	(144.0)	(54.3)
Accrued liabilities	24.7	4.9
Unconsolidated affiliate dividends	—	0.1
Employer contributions to pension & postretirement plans	(6.9)	(3.5)
Changes in noncurrent assets	(29.0)	(28.0)
Changes in noncurrent liabilities	(13.5)	(7.7)
Net cash from operating activities	314.5	360.5
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	299.3	99.2
Dividend reinvestment plan & other common stock issuances	1.7	4.6
Requirements for:		
Dividends on common stock	(112.1)	(104.5)
Retirement of long-term debt	(100.0)	—
Net change in short-term borrowings	75.8	31.5
Net cash from financing activities	164.7	30.8
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from sale of assets and other collections	5.7	4.8
Requirements for:		
Capital expenditures, excluding AFUDC equity	(472.7)	(453.5)
Other costs	—	(3.4)
Changes in restricted cash	—	0.9
Net cash from investing activities	(467.0)	(451.2)
Net change in cash & cash equivalents	12.2	(59.9)
Cash & cash equivalents at beginning of period	16.6	68.6
Cash & cash equivalents at end of period	$28.8	$8.7

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

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 598,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,000 electric customers and approximately 112,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 320,000 natural gas customers located near Dayton in west-central Ohio.

The Company, 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.

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

Subject to the terms and conditions in the Merger Agreement, upon closing, each share of common stock of the Company shall be converted into the right to receive $72.00 in cash without interest.
The Company, CenterPoint and Merger Sub each have made various representations, warranties and covenants in the Merger Agreement. Among other things, the Company has agreed, subject to certain exceptions, to conduct its businesses in the ordinary course, consistent with past practice, from the date of the Merger Agreement until closing, and not to take certain actions prior to the closing of the Merger without the approval of CenterPoint. The Company has made certain additional customary covenants, including, subject to certain exceptions: (1) to cause a meeting of the Company’s shareholders to be held to consider approval of the Merger Agreement, (2) not to solicit proposals relating to alternative business combination transactions and not to participate in discussions concerning, or furnish information in connection with, alternative business combination transactions and (3) not to withdraw its recommendation to the Company’s shareholders regarding the Merger. In addition, subject to the terms of the Merger

Agreement, the Company, CenterPoint and Merger Sub are required to use reasonable best efforts to obtain all required regulatory approvals, which will include clearance under federal antitrust laws and certain approvals by federal regulatory bodies, including the Federal Energy Regulatory Commission ("FERC"), subject to certain exceptions, including such efforts not result in a "Burdensome Condition" (as defined in the Merger Agreement). While approval of the Merger Agreement is not required by the Indiana Utility Regulatory

Commission ("IURC") or the Public Utilities Commission of Ohio ("PUCO"), informational filings have been made with each commission.
Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of the Company, (2) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (3) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (4) absence of any law or order prohibiting the consummation of the Merger and (5) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to the Company and its subsidiaries.
The Merger Agreement contains certain termination rights for both the Company and CenterPoint, including if the Merger is not consummated by April 21, 2019 (subject to extension for an additional six months if all conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for each of the Company and CenterPoint, and provides that, upon termination of the Merger Agreement under certain specified circumstances, CenterPoint would be required to pay a termination fee of $210 million to the Company, and under other specified circumstances the Company would be required to pay CenterPoint a termination fee of $150 million.

On June 15, 2018, Vectren and CenterPoint submitted their filings with the FERC and initiated informational proceedings with regulators in Indiana and Ohio. Further, on June 18, 2018, Vectren and CenterPoint submitted their filings pursuant to the Hart-Scott-Rodino Act and the Federal Communications Commission. On June 26, 2018, CenterPoint and Vectren received notice from the Federal Trade Commission granting early termination of the waiting period under the Hart-Scott-Rodino Act. On July 16, 2018, the Company filed a definitive proxy statement, and a Form 8-K including supplemental disclosures to the proxy statement, with the Securities and Exchange Commission in connection with the Merger. On July 24, 2018, the Federal Communications Commission provided the final approvals for the transfer of control of the Company's subsidiaries which hold radio licenses. At the special shareholders meeting held on August 28, 2018, the Merger Agreement and the Merger, as well as other matters relating to the proposed Merger, were voted on and approved by the Company's shareholders. On October 5, 2018, the FERC issued an order indicating its approval of the Merger. In Indiana, the IURC held a hearing on October 17, 2018 on the Company's informational filing. Final briefs are to be filed by December 21, 2018, and an order is expected in early 2019. A similar informational filing was made in Ohio and, though a hearing before the PUCO is not anticipated, an order is expected in early 2019, as well. As of November 6, 2018, seven purported Company shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in the Company's proxy statement in connection with the Merger as discussed in Note 11. Subject to receipt of remaining approvals, the Company continues to anticipate that the closing of the Merger will occur no later than the first quarter of 2019.

In connection with this transaction, the Company has recorded Merger-related expenses of $11.1 million for the quarter ending September 30, 2018, which are reflected in Merger-related in Operating Expenses in the Condensed Consolidated Statements of Income. Merger-related expenses for the quarter included $10.3 million of transaction advisory and other costs and $0.8 million for the end-of-period measurement of share-based and deferred compensation obligations that resulted from increases in the Company's common stock trading price since the announcement of the Merger. In the nine months ended September 30, 2018, the Company has recorded Merger-related expenses of $26.4 million, including $20.5 million of transaction advisory and other costs and $5.9 million of end-of-period measurement of share-based and deferred compensation obligations. The Company has accounted for these costs as tax deductible since the requisite closing conditions to the Merger have not yet been satisfied. Upon completion of the Merger, the Company will evaluate the tax deductibility of these costs and, though not expected, will reflect any non-deductible amounts in the effective tax rate at the Merger closing date.

2. Basis of Presentation

The interim condensed consolidated financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These interim condensed consolidated financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2017, filed with the Securities and Exchange Commission on February 21, 2018, 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.

3. Revenue

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

On January 1, 2018, the Company adopted the new accounting standard and all the related amendments ("new revenue standard") to all contracts not complete at the date of initial application using the modified retrospective method, which resulted in a cumulative effect reduction of $1.1 million to retained earnings. The Company expects ongoing application to continue to be immaterial to financial condition and net income. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods.

The cumulative effect recorded resulted from a change in the accounting for revenue associated with certain specialized equipment used on projects in the Energy Services segment of the Nonutility Group, where under the new revenue standard, recognition is proportionate to progress in satisfying the performance obligation, and previously was recognized when the equipment was procured.

The cumulative effect of the changes made to the Company's consolidated January 1, 2018 balance sheet for the adoption of the new revenue standard is as follows:

Balance Sheet (In millions)	Balance at December 31, 2017	Adjustments due to ASC 606	Balance at January 1, 2018
Assets			
Accrued unbilled revenues	$ 207.1	$ (7.0)	$ 200.1
Prepayments and other current assets	47.0	5.6	52.6
Liabilities			
Accrued liabilities	222.3	(0.3)	222.0
Common Shareholders' Equity			
Retained earnings	$ 1,113.7	$ (1.1)	$ 1,112.6

The adoption of the new revenue standard had an immaterial impact to the Condensed Consolidated Income Statements for the three and the nine month periods ended September 30, 2018 and the Condensed Consolidated Balance Sheet as of September 30, 2018. The impact was also a result of the change in revenue recognition on specialized equipment.

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

Revenue Policy

Revenue is recognized when obligations under the terms of a contract with the customer are satisfied. Revenue is measured as the amount of consideration the Company expects to receive in exchange for transferring goods or providing services. The satisfaction of performance obligation occurs when the transfer of goods and services occur, which may be at a point in time or over time; resulting in revenue being recognized over the course of the underlying contract or at a single point in time based upon the delivery of services to customers. The Company determines that disaggregating revenue into these categories achieves the disclosure objective to depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. These material revenue generating categories, as disclosed in Note 17, include: Gas Utility Services, Electric Utility Services, Infrastructure Services, and Energy Services.

Utility Group (Gas Utility Services and Electric Utility Services)

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

In the following table, Utility Group revenue is disaggregated by customer class.

(In millions)	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Gas Utility Services		
Residential	$ 80.9	$ 400.9
Commercial	23.7	136.4
Industrial	15.6	56.1
Other	1.9	7.3
Total Gas Utility Services	$ 122.1	$ 600.7
Electric Utility Services		
Residential	$ 63.1	$ 163.5
Commercial	40.3	112.1
Industrial	43.3	121.7
Other	13.3	40.1
Total Electric Utility Services	$ 160.0	$ 437.4

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services. The duration of the contracts is generally less than one year and consist of fixed price, unit, and time and material customer contracts. Under unit or time and material contracts, the Company performs construction and repair services under specific work-orders at prices established by master service agreements. The performance obligation is defined at the work-order level. These services are billed to customers monthly or more frequently for work completed based on units completed or time and material cost incurred, and generally require payment within 30 days of billing. The Company has the right to consideration from customers in an amount that corresponds directly with the performance obligation satisfied, and therefore recognizes revenue at a point in time in the amount to which it has the right to invoice, which results in Accrued unbilled revenues at the end of each accounting period. Under fixed price contracts, the Company performs larger scale construction and repair services. Each contract is typically viewed as a single performance obligation. Services performed under fixed price contracts are typically billed per the terms of the contract, which can range from completion of specific milestones or scheduled billing intervals. Billings occur monthly or more frequently for work completed, and generally require payment within 30 days of billing. Revenue for fixed price contracts are recognized over time as control is transferred using the input method, considering costs incurred relative to total expected cost. Total expected cost is therefore a significant judgment affecting the amount and timing of revenue recognition. Infrastructure Services' revenues are not subject to significant returns, refunds, or warranty obligations.

The following table disaggregates Infrastructure Services revenue by type of contract and timing of transfer of control:

(In millions)	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Revenue		
Unit or time and material (point in time)	$ 167.4	$ 451.2
Fixed price (over time)	139.8	270.7
Total Infrastructure Services	$ 307.2	$ 721.9

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure services. While a majority of Energy Services' revenues are from construction services, some customer contracts also include operation and maintenance services. The performance obligations are distinct as the customer can realize benefits from the construction services without the operation and maintenance services. The prices of each performance obligation are specifically stated in the contract and have been developed independently. Billing methods can vary. Most construction performance obligations require an initial deposit and are either billed monthly for progress completed or according to a contractual draw schedule, which results in Accrued Unbilled Revenues at the end of each accounting period. Payments are typically required within 30 days of billing. Revenues on construction performance obligations, which may have durations greater than one year, are recognized over time as control is transferred using the input method, considering costs incurred relative to total expected cost. Total expected cost is therefore a significant judgment affecting the amount and timing of revenue recognition. Revenue on operations and maintenance performance obligations are recognized ratably over the life of the contract. Energy Services' contracts may be subject to performance guarantees and product warranties as discussed in Note 11.

The following table disaggregates Energy Services revenue by type of performance obligation:

(In millions)	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Revenue		
Construction	$ 69.6	$ 190.3
Operations and maintenance and other	7.1	20.8
Total Energy Services	$ 76.7	$ 211.1

Nonutility Contract Balances

When the timing of the Company’s delivery of nonutility service is different from the timing of the payments made by customers and when the right to consideration is conditioned on something other than the passage of time, the Company recognizes either a contract asset (performance precedes billing) or a contract liability (customer payment precedes performance). Those customers that prepay are represented by contract liabilities until the performance obligations are satisfied. The Company’s contract liabilities are included in Accrued Liabilities in the Condensed Consolidated Balance Sheets. The Company’s contract liabilities primarily relate to contracts in the Energy Services segments where revenue is recognized using the input method. The Company did not have contract assets as of January 1, 2018 or September 30, 2018.

The opening and closing balances of the Company's accounts receivable, accrued unbilled revenue, and contract liabilities are as follows:

(In millions)	Accounts Receivable	Accrued Unbilled Revenues	Contract Liabilities
Opening (01/01/2018)	$ 262.9	$ 200.1	$ 38.3
Closing (09/30/2018)	230.5	156.2	34.1
Increase/(decrease)	$ (32.4)	$ (43.9)	$ (4.2)

The amount of revenue recognized in the nine month period ending September 30, 2018 that was included in the opening contract liability was $38.2 million. The difference between the opening and closing balances of the company’s contract liabilities primarily results from the timing difference between the Company’s performance and the customer’s payment.

Remaining Performance Obligations

The table below discloses (1) the aggregate amount of the transaction price allocated to performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period for contracts and (2) when the company expects to recognize this revenue. Such contracts include both construction and operations and maintenance performance obligations from the Energy Services segment and fixed price contracts in the Infrastructure Services segment.

(In millions)	Rolling 12 Months	Thereafter	Total
Revenue expected to be recognized on contracts in place as of September 30, 2018:			
Energy Services - operations and maintenance	$ 32.5	$ 388.1	$ 420.6
Energy Services - construction	159.6	59.4	219.0
Infrastructure Services - fixed price (bid)	104.8	—	104.8
Total	$ 296.9	$ 447.5	$ 744.4

For the Company’s contracts for which revenue from the satisfaction of the performance obligations is recognized in the amount invoiced, the Company elected the simplified option available in the standard, known as practical expedient, and has not disclosed the revenue expected to be recognized on these contracts.

4. 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.

(In millions, except per share data)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Numerator:				
Reported net income (Numerator for Basic and Diluted EPS)	$ 50.4	$ 61.9	$ 136.1	$ 154.8
Denominator:				
Weighted-average common shares outstanding (Denominator for Basic and Diluted EPS)	83.1	83.0	83.1	83.0
Basic and Diluted EPS	$ 0.61	$ 0.75	$ 1.64	$ 1.87

For the three and nine months ended September 30, 2018 and 2017, all equity based instruments were dilutive and immaterial.

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

6. 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 benefit plan includes health care and life insurance benefits which 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)	2018	2017	2018	2017
Service cost	$1.7	$1.6	$0.1	$0.1
Interest cost	3.2	3.4	0.3	0.4
Expected return on plan assets	(5.3)	(5.3)	—	—
Amortization of prior service cost	0.2	0.1	(0.5)	(0.6)
Amortization of actuarial loss	2.1	1.9	—	—
Settlement charge	—	—	—	—
Net periodic cost (benefit)	$1.9	$1.7	$(0.1)	$(0.1)

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2018	2017	2018	2017
Service cost	$5.1	$4.8	$0.2	$0.2
Interest cost	9.6	10.3	1.0	1.2
Expected return on plan assets	(15.9)	(15.8)		—
Amortization of prior service cost	0.4	0.3	(1.6)	(1.8)
Amortization of actuarial loss	6.3	5.6	—	—
Settlement charge	—	1.9	—	—
Net periodic cost (benefit)	$5.5	$7.1	$(0.4)	$(0.4)

The service cost component is either included within Other operating in the Condensed Consolidated Statements of Income or is capitalized. The components of the net periodic benefit cost other than the service cost component are included within Other income - net in the Condensed Consolidated Statements of Income.

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 has adopted the guidance effective January 1, 2018. In the three and nine month periods ended September 30, 2017, ($0.2) million and $1.0 million, respectively, was retroactively adjusted, increasing Other operating and Other income - net in the Condensed Consolidated Statements of Income in the three month period and decreasing in the nine month period. The Company expects the guidance to have an immaterial impact to the Company's financial statements on an ongoing basis.

Employer Contributions to Qualified Pension Plans

In the nine months ended September 30, 2018, the Company has made $3.5 million in contributions to its qualified pension plans.

7. Supplemental Cash Flow Information

As of September 30, 2018 and December 31, 2017, the Company has accruals related to utility and nonutility plant purchases totaling approximately $40.3 million and $28.6 million, respectively.

8. 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, 2018, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows:

(In millions)	As of September 30, 2018
Cash	$ 0.2
Investment in LA Storage	4.9
Total Investment in ProLiance	$ 5.1
Included in:	
Investments in unconsolidated affiliates	$ 0.7
Other nonutility investments	$ 4.4

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. On June 27, 2018, SE announced a plan to divest of certain natural gas storage assets and recorded an impairment charge related to the assets held for sale and other storage assets, such as LA Storage. As a result of SE's impairment of the LA Storage investment and the resulting charge recorded at Proliance, the Company recorded a $17.7 million charge to Equity in (losses) of unconsolidated affiliates in the three months ended June 30, 2018. The Company's remaining investment in Proliance is supported by the Company's share of the estimated fair value of LA Storage's land. As of September 30, 2018 and December 31, 2017, ProLiance's investment in the joint venture was $8.0 million and $36.8 million, respectively.

9. Income Taxes

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

Tax (“AMT”) and changing how existing AMT credits can be realized, (6) limiting the deductibility of certain executive compensation, (7) restricting the deductibility of entertainment and lobbying-related expenses, (8) requiring regulated entities to employ the average rate assumption method (“ARAM”) to refund excess deferred taxes created by the rate change to their customers, and (9) changing the rules regarding taxability of contributions made by government or civic groups.

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

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

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

On February 9, 2018, through the signing into law of the Bipartisan Budget Act of 2018, Section 179D of the Internal Revenue Code, which provides for the energy efficiency commercial buildings tax deduction, was retroactively extended to 2017 for one year.

10. Financing Activities

SIGECO Variable Rate Tax-Exempt Bonds

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

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

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

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

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

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

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

Term Loans

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

On September 14, 2018, Vectren Capital Corporation (Vectren Capital), which funds short-term and long-term financing needs of the Nonutility Group and corporate operations, closed a two-year term loan with one banking partner. This term loan agreement provided for a $50 million draw at closing and $150 million on or prior to March 31, 2019. Proceeds from the term loan have been utilized for general corporate purposes. The term loan's interest rate is priced at one-month LIBOR, plus a credit spread. In addition, the Vectren Capital term loan contains the same provision stipulating that should the Company or any of its subsidiaries execute certain capital market transactions, and subject to certain other conditions, the outstanding balance is subject to mandatory prepayment. The loan also contains a $50 million accordion feature. The term loan is jointly and severally guaranteed by Vectren Corporation.

As of September 30, 2018, the Company has received term loan proceeds of $300 million ($250 million at Utility Holdings and $50 million at Vectren Capital) and has remaining firm commitments from banking partners of $200 million ($50 million at Utility Holdings and $150 million at Vectren Capital). The remaining draws will be used for general utility purposes and to refund a March 19, 2019 $60 million debt maturity at Vectren Capital.

Utility Holdings and Vectren Capital Borrowing Arrangements

The Merger would constitute a "Change of Control" under the note agreements pursuant to which Senior Notes issued by Utility Holdings in an aggregate principal amount of $1.025 billion and Senior Notes issued by Vectren Capital in an aggregate principal amount of $260 million were issued. While the Merger would not result in an event of default under such note agreements, upon the consummation of the Merger the issuer would be required to offer to repurchase these notes at 100% of the principal amount thereof plus accrued interest.

The Merger will represent an event of default pursuant to the Company's two short-term credit facilities. Upon closing of the merger, CenterPoint will fund the obligations associated with these credit facilities.

11. 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.

Specific to ESG's role as a general contractor in the performance contracting industry, at September 30, 2018, there were 56 open surety bonds supporting future performance. The average face amount of these obligations is $8.7 million, and the largest obligation has a face amount of $41.9 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, 2018, approximately 25 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 to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At September 30, 2018, parent level guarantees support a maximum of $444 million of ESG’s performance 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.

The Company issues letters of credit that support consolidated operations. At September 30, 2018, letters of credit outstanding total $22 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, including those described below, that are likely to have a material adverse effect on its financial condition, results of operations or cash flows.

Litigation Related to the Merger
As of November 6, 2018, seven purported Company shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in the Company's proxy statement in connection with the Merger. These cases are captioned Kuebler v. Vectren Corp., et al., Case No. 3:18-cv-00113-RLY-MPB (S.D. Ind.) (the “Kuebler Action”), Danigelis v. Vectren Corp., et al., Case No. 3:18-cv-00114-RLY-MPB (S.D. Ind.) (the “Danigelis Action”), Scarantino v. Vectren Corp., et al., Case No. 3:18-cv-00115-RLY-MPB (S.D. Ind.) (the “Scarantino Action”), Stein v. Vectren Corp., et al., Case No. 3:18-cv-00117-RLY-MPB (S.D. Ind.) (the “Stein Action”), Nisenshal v. Vectren Corp., et al., Case No.

3:18-cv-00121-RLY-MPB (S.D. Ind.) (the “Nisenshal Action”), VonSalzen v. Vectren Corp., et al., Case No. 3:18-cv-00122-RLY-MPB (S.D. Ind.) (the “VonSalzen Action”), and Kent v. Vectren Corp., et al., Case No. 1:18-cv-02263-SEB-TAB (S.D. Ind.) (the “Kent Action,” referred to together with the preceding actions, as the "Actions"). The Kuebler Action, the Danigelis Action, the Scarantino Action, the Nisenshal Action, and the Kent Action are asserted on behalf of putative classes of Company shareholders, while the Stein Action and the VonSalzen Action are brought only on behalf of their respective named plaintiffs.

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

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

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

On October 29, 2018, lead plaintiffs filed an amended consolidated complaint asserting claims under Sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9 promulgated thereunder based on various alleged omissions of material information from the final proxy statement. Plaintiffs seek compensatory and/or rescissory damages and an award of costs and attorneys' and expert fees.

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

12. Gas Rate & Regulatory Matters

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

infrastructure improvement projects outside of a base rate proceeding.

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

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

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

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

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

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

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

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

In December 2016, PHMSA issued interim final rules related to integrity management for storage operations. Efforts are underway to implement the new requirements. Further, the Company reviewed the Underground Natural Gas Storage

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Safety Recommendations from a joint Department of Energy and PHMSA led task force. On August 3, 2017, the Company filed for authority to recover the associated costs using the mechanism allowed under Senate Bill 251. Approximately $15 million of operating expenses and $17 million of capital investments will be included in the plan over a four-year period beginning in 2018. The Company received the IURC Order approving the request for recovery on December 28, 2017. The Company does not have company-owned storage operations in Ohio.

Ohio Recovery and Deferral Mechanisms

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

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

Vectren Ohio Gas Rate Case

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

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

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

13. Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560
The provisions of Senate Bill 560, as described in Note 12 for gas projects, are the same for qualifying electric projects. On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company’s network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers.

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

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

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

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

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

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

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. The MATS rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Other Generation Developments

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

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

14. Environmental & Sustainability Matters

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

In furtherance of the Company’s commitment to a sustainable business model, and as detailed further below, the Company is transitioning its electric generation portfolio from nearly total reliance on baseload coal to a fully diversified and balanced portfolio of fuels that will provide long term electric supply needs in a safe and reliable manner while dramatically lowering emissions of carbon and the carbon intensity of its electric generating fleet. If authorized by the Commission, by 2024 the Company plans to construct a new natural gas combined cycle generating facility to replace four coal-fired units totaling over 700 MWs which, when combined with its planned 54 MWs of new renewable generation, will achieve a 60 percent reduction in carbon emissions from 2005 levels and reduce carbon intensity to 980 lbs CO2 / MMBTU and position the Company to comply with future carbon emission reduction requirements. In addition to diversification of its fuel portfolio, the Company is also seeking authorization to significantly upgrade wastewater treatment for its remaining coal-fired unit and exploring opportunities to continue to recycle ash from its coal ash ponds. This generation diversification strategy aligns with the Company's ongoing investments in new electric infrastructure through the approved $446.5 million grid modernization program, and is set forth in more detail in the Company's 2017 corporate sustainability report.

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

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

Coal Ash Waste Disposal, Ash Ponds and Water

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

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

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

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

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

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

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

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company’s IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by IDEM provided the Company notifies IDEM of its intent to retire the unit within 30 days of the receipt of the order in the CPCN proceeding. For the F.B. Culley 3 plant, the Company requested a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by IDEM and finalized in the permit renewal. Discussion of these environmental investments at the F.B. Culley 3 plant is included in the generation transition plan in Note 13.

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

Cooling Water Intake Structures

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

Air Quality

Ozone NAAQS

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

One Hour SO2 NAAQS

On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between IDEM and the EPA with respect to the EPA's recommendations for new non-attainment designations for the 2010 One Hour SO_2 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 SO_2 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 SO_2 NAAQS. The Company's coal-fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NO_x.

Climate Change and Carbon Strategy

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

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

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

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

Manufactured Gas Plants

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

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

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

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

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

15. Impact of Recently Issued Accounting Standards

Leases

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

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

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

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

Other Recently Issued Standards

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

16. Fair Value Measurements

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

(In millions)	September 30, 2018		December 31, 2017	
	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$2,038.9	$2,103.5	$1,838.7	$1,981.2
Short-term borrowings	325.3	325.3	249.5	249.5
Cash & cash equivalents	28.8	28.8	16.6	16.6
Natural gas purchase instrument assets (1)	0.1	0.1	0.5	0.5
Natural gas purchase instrument liabilities (2)	14.5	14.5	4.5	4.5
Interest rate swap assets (3)	3.3	3.3	—	—
Interest rate swap liabilities (4)	—	—	1.4	1.4

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

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

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

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

As described in Note 10, the Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging variability in interest rates. The Company values these contracts using a pricing model that incorporates market-based information, and are classified within Level 2 of the fair value hierarchy.

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, 2018 and December 31, 2017, the fair value for these financial instruments was not estimated. The carrying value of these investments was $9.6 million at each of September 30, 2018 and December 31, 2017.

17. 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 Utility Operations.

The Nonutility Group reports the following segments: Infrastructure Services, Energy Services, and Other Nonutility 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 $40.9 million and $46.5 million for the three months ended September 30, 2018 and 2017, respectively, and for the nine months ended September 30, 2018 and 2017 totaled $105.2 million and $123.9 million, respectively. 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.

Corporate and Other includes unallocated corporate expenses such as Merger-related costs, 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)	2018	2017	2018	2017
Revenues				
Utility Group				
Gas Utility Services	$122.1	$120.4	$600.7	$557.2
Electric Utility Services	160.0	159.2	437.4	433.0
Other Operations	11.8	11.4	35.3	34.2
Eliminations	(11.7)	(11.3)	(35.1)	(34.0)
Total Utility Group	282.2	279.7	1,038.3	990.4
Nonutility Group				
Infrastructure Services	307.2	339.9	721.9	764.7
Energy Services	76.7	72.5	211.1	193.2
Total Nonutility Group	383.9	412.4	933.0	957.9
Corporate & Other Group	0.1	0.1	0.3	0.4
Eliminations	(1.2)	(1.0)	(3.7)	(2.4)
Consolidated Revenues	$665.0	$691.2	$1,967.9	$1,946.3
Profitability Measure - Net Income				
Utility Group Net Income				
Gas Utility Services	$(0.6)	$1.0	$60.7	$55.8
Electric Utility Services	30.6	27.2	62.4	56.8
Other Operations	3.0	2.6	9.7	9.6
Utility Group Net Income	33.0	30.8	132.8	122.2
Nonutility Group Net Income				
Infrastructure Services	22.1	26.6	26.0	28.6
Energy Services	4.5	4.9	12.2	4.9
Other Nonutility Businesses	(0.3)	(0.2)	(13.9)	(0.5)
Nonutility Group Net Income	26.3	31.3	24.3	33.0
Corporate & Other Group Net (Loss)	(8.9)	(0.2)	(21.0)	(0.4)
Consolidated Net Income	$50.4	$61.9	$136.1	$154.8

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 598,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,000 electric customers and approximately 112,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 320,000 natural gas customers located near Dayton in west-central Ohio.

The Company, 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 2017 annual report filed on Form 10-K.

Merger with CenterPoint Energy, Inc.

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

Subject to the terms and conditions in the Merger Agreement, upon closing, each share of common stock of the Company shall be converted into the right to receive $72.00 in cash without interest.
The Company, CenterPoint and Merger Sub each have made various representations, warranties and covenants in the Merger Agreement. Among other things, the Company has agreed, subject to certain exceptions, to conduct its businesses in the ordinary course, consistent with past practice, from the date of the Merger Agreement until closing, and not to take certain actions prior to the closing of the Merger without the approval of CenterPoint. The Company has made certain additional customary covenants, including, subject to certain exceptions: (1) to cause a meeting of the Company's shareholders to be held to consider approval of the Merger Agreement, (2) not to solicit proposals relating to alternative business combination transactions and not to participate in discussions concerning, or furnish

information in connection with, alternative business combination transactions and (3) not to withdraw its recommendation to the Company’s shareholders regarding the Merger. In addition, subject to the terms of the Merger Agreement, the Company, CenterPoint and Merger Sub are required to use reasonable best efforts to obtain all required regulatory approvals, which will include clearance under federal antitrust laws and certain approvals by federal regulatory bodies, including FERC, subject to certain exceptions, including such efforts not result in a "Burdensome Condition" (as defined in the Merger Agreement). While approval of the

Merger Agreement is not required by the Indiana Utility Regulatory Commission ("IURC") or the Public Utilities Commission of Ohio ("PUCO"), informational filings have been made with each commission.
Consummation of the Merger is subject to various conditions, including: (1) approval of the shareholders of the Company, (2) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (3) receipt of all required regulatory and statutory approvals without the imposition of a "Burdensome Condition," (4) absence of any law or order prohibiting the consummation of the Merger and (5) other customary closing conditions, including (a) subject to materiality qualifiers, the accuracy of each party's representations and warranties, (b) each party's compliance in all material respects with its obligations and covenants under the Merger Agreement and (c) the absence of a material adverse effect with respect to the Company and its subsidiaries.
The Merger Agreement contains certain termination rights for both the Company and CenterPoint, including if the Merger is not consummated by April 21, 2019 (subject to extension for an additional six months if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for each of the Company and CenterPoint, and provides that, upon termination of the Merger Agreement under certain specified circumstances, CenterPoint would be required to pay a termination fee of $210 million to the Company, and under other specified circumstances the Company would be required to pay CenterPoint a termination fee of $150 million.
On June 15, 2018, Vectren and CenterPoint submitted their filings with the FERC and initiated informational proceedings with regulators in Indiana and Ohio. Further, on June 18, 2018, Vectren and CenterPoint submitted their filings pursuant to the Hart-Scott-Rodino Act and the Federal Communications Commission. On June 26, 2018, CenterPoint and Vectren received notice from the Federal Trade Commission granting early termination of the waiting period under the Hart-Scott-Rodino Act. On July 16, 2018, the Company filed a definitive proxy statement, and a Form 8-K including supplemental disclosures to the proxy statement, with the Securities and Exchange Commission in connection with the Merger. On July 24, 2018, the Federal Communications Commission provided the final approvals for the transfer of control of the Company's subsidiaries which hold radio licenses. At the special shareholders meeting held on August 28, 2018, the Merger Agreement and the Merger, as well as other matters relating to the proposed Merger, were voted on and approved by the Company's shareholders. On October 5, 2018, the FERC issued an order indicating its approval of the Merger. In Indiana, the IURC held a hearing on October 17, 2018 on the Company's informational filing. Final briefs are to be filed by December 21, 2018, and an order is expected in early 2019. A similar informational filing was made in Ohio and, though a hearing before the PUCO is not anticipated, an order is expected in early 2019, as well. As of November 6, 2018, seven purported Company shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in the Company's proxy statement in connection with the Merger as discussed in Note 11. Subject to receipt of remaining approvals, the Company continues to anticipate that the closing of the Merger will occur no later than the first quarter of 2019.

Executive Summary of Consolidated Results of Operations

In 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, 2018 were earnings of $50.4 million, or $0.61 per share, compared to earnings of $61.9 million, or $0.75 per share for the three months ended September 30, 2017. For the nine months ended

September 30, 2018, consolidated net income was $136.1 million or $1.64 per share, compared to $154.8 million or $1.87 per share for the nine months ended September 30, 2017. Excluding reconciling items as defined below, consolidated net income for the three and nine months ended September 30, 2018 were $59.2 million, or $0.71 per share, and $169.4 million, or $2.04 per share, respectively. Also reflected in the nine months ended September 30, 2018 results is income of $4.9 million, or $0.06 per share, related to Section 179D tax deductions.

Reconciling Items

Management believes analyzing underlying and ongoing business trends is aided by the removal of these reconciling items and the rationale for using such non-GAAP measures is that the Company would not expect these items to be indicative of ongoing operations.

Merger-Related Costs
In connection with the Merger, the Company recorded Merger-related expenses of $11.1 million for the quarter ending September 30, 2018, which are reflected in Merger-related in Operating Expenses in the Condensed Consolidated Statements of Income. Merger related expenses for the quarter include $10.3 million of transaction advisory and other costs and $0.8 million for the end of period measurement of share-based and deferred compensation obligations that resulted from increases in the Company’s common stock trading price since the announcement of the Merger. In the nine months ended September 30, 2018, the Company recorded Merger-related expenses of $26.4 million, including $20.5 million of transaction advisory and other costs and $5.9 million of end of period measurement of share-based and deferred compensation obligations.

Equity Investment Impairment Charge - ProLiance
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. On June 27, 2018, SE announced a plan to divest of certain natural gas storage assets and recorded an impairment charge related to the assets held for sale and other storage assets, such as LA Storage. As a result of SE's impairment of the LA Storage investment and the resulting charge recorded at Proliance, in the nine months ended September 30, 2018, the Company recorded a $17.7 million charge to Equity in (losses) of unconsolidated affiliates. The Company's remaining investment in Proliance is supported by the Company's share of the estimated fair value of LA Storage's land. As of September 30, 2018 and December 31, 2017, ProLiance's investment in the joint venture was $8.0 million and $36.8 million, respectively.

Consolidated Results Excluding Reconciling Items (See the following pages regarding the Use of Non-GAAP Measures)

Net income (loss) and earnings per share, excluding reconciling items for the three and nine months ended September 30, 2018 and 2017 follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2018	2017	2018	2017
Net income, excluding reconciling items	$59.2	$61.9	$169.4	$154.8
Attributed to:				
Utility Group	33.0	30.8	132.8	122.2
Nonutility Group, excluding Equity Investment Impairment Charge - ProLiance	26.3	31.3	37.4	33.0
Corporate & other, excluding Merger-Related Costs	(0.1)	(0.2)	(0.8)	(0.4)
Basic EPS, excluding reconciling items	$0.71	$0.75	$2.04	$1.87
Attributed to:				
Utility Group	0.40	0.37	1.60	1.47
Nonutility Group, excluding Equity Investment Impairment Charge - ProLiance	0.32	0.38	0.45	0.40
Corporate & other, excluding Merger-Related Costs	(0.01)	—	(0.01)	—

Utility Group

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

Nonutility Group

The Nonutility group results for the third quarter of 2018 were earnings of $26.3 million, compared to earnings of $31.3 million in the prior year. For the nine months ended September 30, 2018, excluding the charge recorded related to its equity investment in certain storage assets jointly owned by Sempra, the Nonutility Group reported earnings of $37.4 million, compared to earnings of $33.0 million in the prior year period. The nine months ended September 30, 2018 results also reflect $4.9 million of earnings related to IRS Code section 179D deductions. Decreases in the quarter, partially offset by the Energy Services business and the benefit from the lower tax rate, were primarily driven by the Infrastructure Services business, were due to a large project with substantial activity in the third quarter of 2017.

Dividends

Dividends declared for the three months ended September 30, 2018 were $0.45 per share, compared to $0.42 per share in 2017. Dividends declared for the nine months ended September 30, 2018, were $1.35 per share, compared to $1.26 per share in 2017.

Under the Merger Agreement, the Company may not declare or pay dividends or distributions on common stock in an amount in excess of $0.45 per share for quarterly dividends declared before October 31, 2018 and $0.48 per share for quarterly dividends declared on or after October 31, 2018. The Company declared a dividend of $0.48 per share on November 1, 2018.

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Use of Non-GAAP Performance Measures and Per Share Measures

Utility Group Margin

Throughout this discussion, the terms Gas utility margin and Electric utility margin are used, which are non-GAAP measures. Gas utility margin is calculated as Gas utility revenues less the Cost of gas sold. Electric utility margin is calculated as Electric utility revenues less Cost of fuel & purchased power. These measures are not specifically defined by GAAP, and therefore, are non-GAAP. The Company believes Gas utility margins and Electric utility margins are better indicators of relative contribution than Gas utility revenues and Electric utility revenues, their closest GAAP measures, since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers. These non-GAAP measures should not be considered a substitute for, or superior to, measures calculated in accordance with GAAP.

Results Excluding Reconciling Items

This discussion and analysis contains non-GAAP financial measures that exclude reconciling items in 2018, involving Merger-related costs and the equity investment impairment charge.

Management uses net income and earnings per share (EPS), excluding reconciling items activity, to evaluate its results. Management believes analyzing underlying and ongoing business trends is aided by the removal of these reconciling items and the rationale for using such non-GAAP measures is that the Company would not expect these items to be indicative of ongoing operations. Management believes this presentation provides the best representation of the overall results and certain components of the financial statements for ongoing operations.

A material limitation associated with the use of these measures is that measures excluding reconciling items does not include all activity recognized in accordance with GAAP. Management compensates for this limitation by prominently displaying a reconciliation of these non-GAAP performance measures to their closest GAAP performance measures. This display also provides financial statement users the option of analyzing results as management does or by analyzing GAAP results.

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 GAAP earnings per share of Utility Group, Nonutility Group, and Corporate and Other. 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.

The following tables reconcile net income, basic EPS, and certain components from the financial statements from the GAAP measure to the non-GAAP measure in 2018.

(In millions, except EPS)	Three Months Ended September 30, 2018		
	GAAP Measure	Merger-Related Costs	Non-GAAP Measure
Net Income and EPS by Segment			
Consolidated			
Net Income	$50.4	$ 8.8	$ 59.2
Basic EPS	$0.61	$ 0.10	$ 0.71
Corp & Other			
Net Income (loss)	$(8.9)	$ 8.8	$ (0.1)
Basic EPS	$(0.11)	$ 0.10	$ (0.01)
Income Statement Line Item by Segment			
Merger-Related			
Consolidated	$11.1	$ (11.1)	$ —
Corp & Other	$11.1	$ (11.1)	$ —
Income Taxes			
Consolidated	$10.6	$ 2.3	$ 12.9
Nonutility Group	$7.4	$ —	$ 7.4
Corp & Other	$(2.5)	$ 2.3	$ (0.2)

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(In millions, except EPS)	Nine Months Ended September 30, 2018			
	GAAP Measure	Merger-Related Costs	Equity Investment Impairment Charge	Non-GAAP Measure
Net Income and EPS by Segment				
Consolidated				
Net Income	$136.1	$ 20.2	$ 13.1	$ 169.4
Basic EPS	$1.64	$ 0.24	$ 0.16	$ 2.04
Nonutility Group				
Net Income	$24.3	$ —	$ 13.1	$ 37.4
Basic EPS	$0.29	$ —	$ 0.16	$ 0.45
Corp & Other				
Net Income (loss)	$(21.0)	$ 20.2	$ —	$ (0.8)
Basic EPS	$(0.25)	$ 0.24	$ —	$ (0.01)
Income Statement Line Item by Segment				
Merger-Related				
Consolidated	$26.4	$ (26.4)	$ —	$ —
Corp & Other	$26.4	$ (26.4)	$ —	$ —
Equity in (losses) from unconsolidated affiliates				
Consolidated	$(18.3)	$ —	$ 17.7	$ (0.6)
Corp & Other	$(18.3)	$ —	$ 17.7	$ (0.6)
Income Taxes				
Consolidated	$18.2	$ 6.2	$ 4.6	$ 29.0
Nonutility Group	$0.1	$ —	$ 4.6	$ 4.7
Corp & Other	$(6.5)	$ 6.2	$ —	$ (0.3)

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

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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, 2018 and 2017 follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2018	2017	2018	2017
OPERATING REVENUES				
Gas utility	$122.1	$120.4	$600.7	$557.2
Electric utility	160.0	159.2	437.4	433.0
Other	0.1	0.1	0.2	0.2
Total operating revenues	282.2	279.7	1,038.3	990.4
OPERATING EXPENSES				
Cost of gas sold	24.5	23.9	211.4	174.0
Cost of fuel & purchased power	47.5	44.1	137.7	128.8
Other operating	83.5	82.0	265.6	250.4
Depreciation & amortization	63.4	59.0	186.3	174.3
Taxes other than income taxes	13.5	12.6	47.5	40.1
Total operating expenses	232.4	221.6	848.5	767.6
OPERATING INCOME	49.8	58.1	189.8	222.8
OTHER INCOME - NET	9.2	8.1	27.9	21.4
INTEREST EXPENSE	20.3	18.3	60.3	53.5
INCOME BEFORE INCOME TAXES	38.7	47.9	157.4	190.7
INCOME TAXES	5.7	17.1	24.6	68.5
NET INCOME	$33.0	$30.8	$132.8	$122.2
CONTRIBUTION TO VECTREN BASIC EPS	$0.40	$0.37	$1.60	$1.47

Gas Utility Margin (non-GAAP measure) (Gas utility revenues less the cost of gas sold)

Gas utility margin and throughput by customer type follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2018	2017	2018	2017
Gas utility revenues	$122.1	$120.4	$600.7	$557.2
Cost of gas sold	24.5	23.9	211.4	174.0
Total gas utility margin (non-GAAP)	$97.6	$96.5	$389.3	$383.2
Margin attributed to:				
Residential & commercial customers	$72.8	$72.4	$290.2	$293.1
Industrial customers	14.8	15.9	52.6	53.1
Other	1.4	1.5	6.8	6.4
Regulatory expense recovery mechanisms	8.6	6.7	39.7	30.6
Total gas utility margin (non-GAAP)	$97.6	$96.5	$389.3	$383.2
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	5.9	6.0	76.6	59.3
Industrial customers	31.1	25.4	109.8	87.2
Total sold & transported volumes	37.0	31.4	186.4	146.5

Gas utility margins were $97.6 million and $389.3 million for the three and nine months ended September 30, 2018, and compared to 2017, increased $1.1 million quarter over quarter and $6.1 million year over year. Gas utility margins increased $6.8 million in the quarter and $26.9 million year over year when excluding margin from regulatory expense recovery mechanisms, which increased $1.9 million quarter over quarter and $9.1 million year over year, and the impact of tax reform and the reduced corporate tax rate on margins, which in the quarter reduced margins by $7.6 million and year to date by $29.9. Gas margin was favorably impacted by increased returns on infrastructure replacement programs in Indiana and Ohio of $6.3 million quarter over quarter and $21.0 million year over year. Large customer margins were up $0.3 million quarter over quarter and

$2.9 million year over year, largely driven by favorable weather compared to the first quarter of 2017. With rate designs that substantially limit the impact of weather on small customer margin, the normal weather in the first nine months of 2018 compared to the warmer than normal weather in the first nine months of 2017 increased sold and transported volumes, but had only a slight favorable impact on small customer margin. Heating degree days were 102 percent of normal in Ohio and 99 percent of normal in Indiana in the first nine months of 2018, compared to 89 percent of normal in Ohio and 80 percent of normal in Indiana in the same period in 2017.

Electric Utility Margin (non-GAAP measure) (Electric utility revenues less the cost of fuel and purchased power)
Electric utility margin and volumes sold by customer type follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2018	2017	2018	2017
Electric utility revenues	$160.0	$159.2	$437.4	$433.0
Cost of fuel & purchased power	47.5	44.1	137.7	128.8
Total electric utility margin (non-GAAP)	$112.5	$115.1	$299.7	$304.2
Margin attributed to:				
Residential & commercial customers	$73.6	$76.4	$192.6	$197.0
Industrial customers	25.0	26.4	69.6	73.2
Other	0.7	0.9	1.9	2.8
Regulatory expense recovery mechanisms	4.9	3.3	13.4	8.1
Subtotal: retail	$104.2	$107.0	$277.5	$281.1
Wholesale power & transmission system margin	8.3	8.1	22.2	23.1
Total electric utility margin (non-GAAP)	$112.5	$115.1	$299.7	$304.2
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	809.7	796.5	2,148.3	2,042.8
Industrial customers	613.6	587.8	1,668.6	1,600.7
Other customers	5.1	5.1	16.0	16.0
Total retail volumes	1,428.4	1,389.4	3,832.9	3,659.5
Wholesale	121.9	56.7	468.6	295.9
Total volumes sold	1,550.3	1,446.1	4,301.5	3,955.4

Retail

Electric retail utility margins were $104.2 million and $277.5 million for the three and nine months ended September 30, 2018, and compared to 2017, decreased by $2.8 million quarter over quarter and $3.6 million year over year. Electric retail utility margins increased $3.8 million quarter over quarter and $12.6 million year over year, when excluding margin from regulatory expense recovery mechanisms, which increased $1.6 million quarter over quarter and $5.3 million year over year, and the impact of tax reform and the reduced corporate tax rate on margins, which in the quarter reduced margins by $8.2 million and year to date by $21.5 million. Electric margin, which is not protected by weather normalizing mechanisms, reflects a $3.3 million increase in customer margin in the quarter and $12.3 increase year to date related to weather. In the quarter, annualized cooling degree days were 111 percent of normal, compared to 100 percent of normal in 2017. Year to date, annualized cooling degree days were 130 percent of normal, compared to 108 percent of normal in 2017. Year to date results also reflect favorable heating degree days, which were 99 percent of normal in the 2018 year to date period compared to 80 percent of normal in 2017.

Margin from Wholesale Electric Activities

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

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

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $7.0 million and $7.4 million during the three months ended September 30, 2018 and 2017, respectively. Transmission system margin was $17.7 million and $20.0 million during the nine months ended September 30, 2018 and 2017, respectively. The impact of tax reform reduced MISO Transmission system margins by $0.5 million and $1.5 million in the three and nine months ended September 30, 2018, respectively. The Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.9 million at September 30, 2018. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. These projects earn a FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued a final order authorizing the transmission owners to receive a 10.32 percent base ROE plus, a separately approved 50 basis point adder compared to the previously authorized 12.38 percent. The Company has reflected these outcomes in its financial statements. The 345 kV project is the largest of these qualifying projects, with an original cost of $106.8 million that earned the FERC approved equity rate of return.

In the third quarter of 2018, margin from off system sales was $1.3 million compared to $0.7 million in 2017. For the nine months ended September 30, 2018, margin from off-system sales was $4.5 million compared to $3.1 million in 2017. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year to be shared equally with customers. Results for the periods presented are net of sharing and are consistent with the prior period.

Utility Group Operating Expenses

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

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

Taxes Other Than Income Taxes
Taxes other than income taxes were $13.5 million and $12.6 million for the third quarter of 2018 and 2017, respectively. Year to date, taxes other than income taxes were $47.5 million, compared to $40.1 million in 2017. The

increase in taxes other than income taxes in the quarter and year to date periods compared to 2017 was primarily related to higher property taxes, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Income Taxes

Income taxes were $5.7 million and $17.1 million for the third quarter of 2018 and 2017, respectively. Year to date, income taxes were $24.6 million, compared to $68.5 million in 2017. The decreases relate primarily to the decline in the federal income tax rate from 35% to 21%, effective January 1, 2018, as well as the amortization of excess deferred income taxes beginning in the first quarter of 2018. Both the tax rate change and the excess deferred tax amortization relate directly to the passage of the TCJA in December 2017 and have associated revenue reductions.

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

Gas Rate & Regulatory Matters

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

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

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

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

Requests for Recovery under Indiana Regulatory Mechanisms
In August 2014, the IURC issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan (the Plan), beginning in 2014, and the proposed accounting authority and recovery. Compliance projects and other infrastructure improvement projects were approved pursuant to Senate Bill 251 and 560, respectively. As provided in the statutes, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and

recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update the seven-year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

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

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

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

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

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

Ohio Recovery and Deferral Mechanisms

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

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House

Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. The Company has requested recovery of these deferrals through December 31, 2017 in its rate case, along with a mechanism to recover future Ohio House Bill 95 deferrals. At September 30, 2018 and December 31, 2017, the Company has regulatory assets totaling $90.1 million and $66.1 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. On May 1, 2018, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

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

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

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

Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560
The provisions of Senate Bill 560, as described in Note 12 for gas projects, are the same for qualifying electric projects. On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company’s network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers.

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

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

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

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

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

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

SIGECO Electric Environmental Compliance Filing

On January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments in its coal-fired generation units to comply with new EPA mandates related to mercury and air toxic standards (MATS) effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA pertaining to its A.B. Brown generating station sulfur trioxide emissions. The MATS rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants.

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

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

SIGECO Electric Demand Side Management (DSM) Program Filing

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Other Generation Developments

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

On September 28, 2017, the Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR) to the FERC for consideration of payment to certain resources that have on-site fuel and demonstrate a form of resilience. On January 8, 2018, after receiving a majority of comments from the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) opposing the relief requested by the DOE, the FERC declined to issue the NOPR and, instead, initiated a proceeding (FERC Docket No. AD18-7) to further explore the current planning that RTOs and ISOs are undertaking to ensure resiliency, as well as other regional aspects to determine the need for action of the type recommended by the DOE. This proceeding is still pending before the FERC. In the interim, a draft memorandum that was purportedly prepared by the DOE was made public on May 31, 2018. The draft memorandum calls for immediate action by the President of the United States to exercise authority under the Defense Production Act and Federal Power Act to provide for temporary subsidy payments to coal and nuclear resources while a two year study is performed to identify Defense Critical Electric Infrastructure (DCEI). The draft memorandum expands upon the original resiliency concerns expressed in the DOE's September 28, 2017 submission.

Following the publication of the draft DOE memorandum, the President publicly called for immediate action by the DOE. To date, the DOE has not publicly acted, including finalizing the draft memorandum and indicating facilities that would be eligible for these temporary subsidy payments or how they would be funded. At this time, the Company does not believe this activity will have any impact on its pending request for authorization from the IURC to construct a combined cycle gas turbine to serve the requirements of the Company's electric utility system. Absent further information, the impact to electric customers and power generator owners is unknown.

Environmental & Sustainability Matters

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

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

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

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

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August 2017, the

EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. On July 17, 2018, EPA released its final CCR rule phase I reconsideration which extends for two years, from October 31, 2018 to October 31, 2020, the deadline for ceasing placement of ash in ponds that exceed groundwater protections standards or fails to meet location restrictions. The Company does not anticipate the reconsideration to change its current plans for pond closure as announced in its generation transition plan, since closure dates were not dependent upon the original October 2018 compliance date. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect. On August 21, 2018, the U.S. Court of Appeals for the D.C. Circuit issued an opinion in the underlying judicial review litigation, agreeing largely with the environmental challengers by vacating and remanding provisions of the 2015 rule that allowed unlined ash ponds to receive coal ash until a leak is detected and exempted inactive “legacy” impoundments. This decision effectively undercuts further attempts by EPA to make the rule less stringent on reconsideration.

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

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

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

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

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

Effluent Limitation Guidelines (ELG)

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

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company’s IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by IDEM provided the Company notifies IDEM of its intent to retire the unit within 30 days of the receipt of the order in the CPCN proceeding. For the F.B. Culley 3 plant, the Company requested a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by IDEM and finalized in the permit renewal. Discussion of these environmental investments at the F.B. Culley 3 plant is included in the generation transition plan in Note 13.

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

Cooling Water Intake Structures

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

Air Quality

Ozone NAAQS

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

November 2017, EPA finalized its designations of Vanderburgh, Posey, and Warrick counties as being in attainment with the current 70 ppb standard.

One Hour SO2 NAAQS

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

Climate Change and Carbon Strategy

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

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

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

Current Initiatives to Increase Conservation & Reduce Emissions

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

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

- Implementing home and business energy efficiency initiatives in the Company's Indiana and Ohio gas utility service territories such as offering rebates on high efficiency furnaces, programmable thermostats, and insulation and duct sealing;
- Implementing home and business energy efficiency initiatives in the electric service territory such as

rebate programs on central air conditioning units, LED lighting, home weatherization and energy audits;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Further reducing the Company's carbon footprint by building a more sustainable vehicle fleet with lower overall fuel consumption;
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets;
- Working with the Company's gas supply administrator in Indiana to maximize the amount of natural gas delivered to our customers that has been sourced from members of The Environmental Partnership, an organization that includes many of the major oil and gas producers in the U.S and who have committed to continuously improving the industry's environmental performance;
- 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.

Clean Power Plan and ACE Rule

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which required a 32 percent reduction in carbon emissions from 2005 levels. This would result in a final emission rate goal for Indiana of 1,242 lb CO2/MWh to be achieved by 2030 and implemented through a state implementation plan. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA's reconsideration of the CPP rule, which was granted on April 28, 2017. Moreover, as indicated above, in October 2017, EPA published its proposal to repeal the CPP. Comments to the repeal proposal were due in April 2018. EPA's repeal proposal was quickly followed by an advanced notice of proposed rulemaking intended to solicit public comments on issues related to formulating a CPP replacement rule, which were similarly due in April 2018.

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

Impact of Legislative Actions & Other Initiatives

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

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

Manufactured Gas Plants

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

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

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

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

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

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 $26.3 million and $37.4 million for the three and nine months ended September 30, 2018, respectively, compared to earnings of $31.3 million and $33.0 million for the three and nine months ended September 30, 2017. Nonutility Group earnings, excluding the equity investment impairment charge in the nine months ended September 30, 2018, follow. See Executive Summary of Consolidated Results of Operations for a reconciliation of Non-GAAP performance measures.

(In millions, except per share amounts)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
NET INCOME, EXCLUDING EQUITY INVESTMENT IMPAIRMENT CHARGE - PROLIANCE	$26.3	$31.3	$37.4	$33.0
CONTRIBUTION TO VECTREN BASIC EPS, EXCLUDING EQUITY INVESTMENT IMPAIRMENT CHARGE - PROLIANCE	$0.32	$0.38	$0.45	$0.40
NET INCOME (LOSS) ATTRIBUTED TO:				
Infrastructure Services	$22.1	$26.6	$26.0	$28.6
Energy Services	4.5	4.9	12.2	4.9
Other Nonutility Businesses, Excluding Equity Investment Impairment Charge - ProLiance	(0.3)	(0.2)	$(0.8)	$(0.5)

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 2018 were earnings of $22.1 million, compared to earnings of $26.6 million for the same period in the prior year. During the nine months ended September 30, 2018, Infrastructure Services earned $26.0 million, compared to earnings of $28.6 million year to date in 2017. Total Infrastructure Services revenues in the third quarter of 2018 were $307.2 million compared to revenues of $339.9 million in the third quarter of 2017. Year to date, 2018 revenues totaled $721.9 million, compared to $764.7 million for the year to date period in 2017. The lower results in 2018 occurred primarily due to substantial activity from a large project in 2017. Both the quarter and year to date periods were favorably impacted by the lower federal tax rate. At September 30, 2018, Infrastructure Services had an estimated backlog of blanket contracts of $610 million and bid contracts of $105 million, for a total backlog of $715 million. This compares to an estimated total backlog at September 30, 2017 of $755 million, which included $40 million related to the large transmission project that was completed in the fourth quarter of 2017.

The fundamental business model related to the long cycle of integrity, station, and maintenance work in the transmission sector and infrastructure replacement in the distribution sector remains unchanged. Demand remains high due to the aging infrastructure and evolving safety and reliability regulations. While the focus remains on the recurring work in both sectors, opportunities for large transmission pipeline construction projects will continue to be pursued. Though the timing and recurrence of large transmission projects is less predictable, the large projects provide strong revenues.

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 $4.5 million during the third quarter of 2018, compared to earnings of $4.9 million during the third quarter of 2017. For the nine months ended September 30, 2018, earnings were $12.2 million, compared to earnings of $4.9 million in 2017. Excluding the favorable impact of Section 179D tax deductions in the nine months ended September 30, 2018 of $4.9 million, earnings were $7.3 million. Energy Services has year to date revenues of $211.1 million in 2018, compared to revenues of $193.2 million for the year to date period in 2017.

At September 30, 2018, the backlog of signed fixed price contracts is $219 million compared to $180 million at December 31, 2017. The list of projects at September 30, 2018 where ESG has been selected and there is a high degree of confidence that the stated work will be performed, or sales funnel, totals nearly $370 million. 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. As it relates to the impact on results from Section 179D, on February 9, 2018, a one year extension of Section 179D was approved, making available deductions for the 2017 tax year. Though not assured and not reflected in long-term growth rates, efforts continue to secure this benefit in the future.

Other Nonutility Businesses

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.

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (Sempra), 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. On June 27, 2018, Sempra announced a plan to divest of certain natural gas storage assets and recorded a resulting impairment charge related to the assets held for sale and other storage assets, such as LA Storage. As a result of Sempra's impairment to the LA Storage investment and the resulting charge recorded at Proliance, the Company recorded a $17.7 million charge to Equity in (losses) of unconsolidated affiliates in the three months ended June 30, 2018. The Company's remaining investment in Proliance is supported by the Company's share of the estimated fair value of LA Storage's land. As of September 30, 2018 and December 31, 2017, ProLiance's investment in the joint venture was $8.0 million and $36.8 million, respectively.

Impact of Recently Issued Accounting Standards

Leases

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

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

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

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

Other Recently Issued Standards

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

Financial Condition

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, 2018 approximated $309 million. Vectren Capital's short-term obligations outstanding at September 30, 2018 approximated $100 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, 2018 approximated $1.346 billion and $225 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, 2018 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, 2018, 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. S&P Global and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

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

The Company’s consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on 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 48 percent as of September 30, 2018 and 50 percent as of December 31, 2017. 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, 2018, the Company was in compliance with all debt covenants.

Available Liquidity
The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and as evidenced by past financing transactions, the Company believes it will have the ability to continue to do so. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds, supplemented with incremental external 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, Merger-related costs, 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.

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

Term Loans

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

On September 14, 2018, Vectren Capital closed a two-year term loan with one banking partner. This term loan agreement provided for a $50 million draw at closing and $150 million on or prior to March 31, 2019. Proceeds from the term loan have been utilized for general corporate purposes. The term loan’s interest rate is priced at one-month LIBOR, plus a credit spread. In addition, the Vectren Capital term loan contains the same provision stipulating that should the Company or any of its subsidiaries execute certain capital market transactions, and subject to certain other conditions, the outstanding balance is subject to mandatory prepayment. The loan also contains a $50 million accordion feature. The term loan is jointly and severally guaranteed by Vectren Corporation.

As of September 30, 2018, the Company has received term loan proceeds of $300 million ($250 million at Utility Holdings and $50 million at Vectren Capital) and has remaining firm commitments from banking partners of $200 million ($50 million at Utility Holdings and $150 million at Vectren Capital). The remaining draws will be used for general utility purposes and to refund a March 19, 2019 $60 million debt maturity at Vectren Capital.

SIGECO Variable Rate Tax-Exempt Bonds

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

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

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

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

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

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

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

Consolidated Short-Term Borrowing Arrangements
At September 30, 2018, the Company had $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 $175 million was available for the Utility Group operations and $100 million was available for the wholly owned Nonutility Group and corporate operations. These short-term credit facilities were extended in July 2017 and are available through July 2022.

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

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2018	2017	2018	2017
As of September 30				
Balance Outstanding	$225.3	$211.7	$100.0	$14.2
Weighted Average Interest Rate	2.34%	1.39%	3.33%	2.33%
Nine Months Ended September 30 Average				
Balance Outstanding	$177.2	$161.6	$112.4	$11.1
Weighted Average Interest Rate	2.18%	1.22%	3.12%	2.37%
Maximum Month End Balance Outstanding	$262.0	$238.7	$156.6	$35.3

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2018	2017	2018	2017
Quarterly Average - September 30				
Balance Outstanding	$191.5	$210.9	$142.5	$28.2
Weighted Average Interest Rate	2.31%	1.41%	3.28%	2.38%
Maximum Month End Balance Outstanding	$225.3	$238.7	$156.6	$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 $1.7 million for the nine months ended September 30, 2018 and $4.6 million for the nine months ended September 30, 2017. The Merger Agreement limits the Company's ability to issue new shares.

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Impact of Tax Reform on Liquidity
The Company has realized cash flow benefits from tax legislation, such as the Protecting Americans from Tax Hikes (Path Act) enacted in 2015, which allowed for immediate expensing of 50 percent of capital expenditures through 2017 for tax purposes. Such accelerated expense recognition reduced tax payments due to the government. The TCJA enacted on December 22, 2017, which eliminates the accelerated expensing provisions for regulated utilities and reduces the corporate tax rate to 21 percent, has reduced, and will continue to reduce liquidity by 1) reducing the Utility Group's ability to accelerate expense for capital expenditures for tax purposes and 2) reducing cash collected from customers due to the lower tax rate. The Company expects the reduced federal corporate income tax rate will result in reduced taxes owed by the Nonutility Group, increasing liquidity.

Utility Holdings and Vectren Capital Long-Term Borrowing Facilities
The Merger would constitute a "Change of Control" under the note agreements pursuant to which Senior Notes issued by Utility Holdings in an aggregate principal amount of $1.025 billion and Senior Notes issued by Vectren Capital in an aggregate principal amount of $260 million were issued. While the Merger would not result in an event of default under such note agreements, upon the consummation of the Merger the issuer would be required to offer to repurchase these notes at 100% of the principal amount thereof plus accrued interest.

The Merger will represent an event of default pursuant to the Company's two short-term credit facilities. Upon closing of the Merger, CenterPoint will fund the obligations associated with these credit facilities.

Potential Uses of Liquidity

Pension Funding Obligations
For the nine months ended September 30, 2018, the Company contributed $3.5 million to its qualified pension plans. The Company does not anticipate making any additional payments for the remainder of 2018.

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, 2018, there are 56 open surety bonds supporting future performance. The average face amount of these obligations is $8.7 million, and the largest obligation has a face amount of $41.9 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, 2018, approximately 25 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 to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At September 30, 2018, parent level guarantees support a maximum of $444 million of ESG's 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.

The Company, from time to time, issues letters of credit that support consolidated operations. At September 30, 2018, letters of credit outstanding total $22 million.

Planned Capital Expenditures & Investments
Utility capital expenditures are estimated at approximately $150 million for the remainder of 2018. Nonutility capital expenditures are estimated at approximately $39 million for the remainder of 2018.

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, 2018, there were no significant changes to the Company’s contractual obligations from those identified in the Company’s Annual Report on Form 10-K for the year ended December 31, 2017, other than those which occur in the normal and ordinary course of business and those mentioned below.

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

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow
The Company's primary source of liquidity to fund capital requirements has been cash generated from operations, which totaled $314.5 million and $360.5 million for the nine months ended September 30, 2018 and 2017, respectively. The decrease in operating cash flow for the nine months ended September 30, 2018 compared to 2017 is driven primarily by the Company’s $69.7 million contribution to the Vectren Foundation, a 501(c)(3) charitable organization, affiliated with, but separate from, Vectren Corporation and reflected in Accounts payable at December 31, 2017 in the Condensed Consolidated Balance Sheets and changes in certain working capital accounts.

Financing Cash Flow
Net cash flow proceeds from financing activities were $164.7 million during the nine months ended September 30, 2018 compared to proceeds of $30.8 million in 2017. The increase in financing cash flow for the nine months ended September 30, 2018 compared to 2017 is driven primarily by a new term loan and short-term borrowings which were utilized for the retirement of debt, funding the Vectren Foundation and increased capital expenditures. Financing activity in both periods presented reflects the payment of dividends.

Investing Cash Flow

Cash flow required for investing activities was $467.0 million and $451.2 million during the nine months ended September 30, 2018 and 2017, respectively. The increase in investing activity in 2018 primarily reflects higher capital expenditures for the Utility Group.

Under the Merger Agreement, the Company can no longer issue shares of the Company's common stock or have indebtedness (including long-term debt, current maturities of long-term debt, and short-term borrowings), in excess of $2.534 billion at December 31, 2018 without the consent of CenterPoint.

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 included in this Quarterly Report on Form 10-Q are forward-looking statements, including but not limited to, statements concerning the expected timing, outcome, and operational and financial impacts of ongoing litigation, regulatory proceedings, proposed environmental regulations, legislative actions, and accounting standards, as well as statements concerning estimated future revenues, capital expenditures, and financing needs. Such statements are based on management’s beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words “believe”, “anticipate”, “endeavor”, “estimate”, “expect”, “objective”, “projection”, “forecast”, “goal”, “likely”, and similar expressions are intended t forward-looking statements.

Risks Related to the Merger

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

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

Risks Related to the Company

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

- Factors affecting utility operations such as unfavorable or unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.

- New or proposed legislation, litigation and government regulation or other actions, such as changes in, rescission of or additions to tax laws or rates, pipeline safety regulation and environmental laws and regulations, including laws governing air emissions, carbon, waste water discharges and the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of generation plant costs and related assets. Compliance with respect to these regulations could substantially change the operation and nature of the Company’s utility operations.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, or physical attacks could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Cyber attacks or similar occurrences may adversely affect the Company's facilities, operations, corporate reputation, financial condition, and results of operations.
- Approval and timely recovery of new capital investments related to the electric generation transition plan, discussed further herein, including timely approval to build and own generation, ability to meet capacity requirements, ability to procure resources needed to build new generation at a reasonable cost, ability to appropriately estimate costs of new generation, the effects of construction delays and cost overruns, ability to fully recover the investments made in retiring portions of the current generation fleet, scarcity of resources and labor, and workforce retention, development and training.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation, commodity prices, and monetary fluctuations.
- Economic conditions, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, 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, key business personnel, 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 2017 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, 2018, there have been no changes to the Company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of September 30, 2018, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of

September 30, 2018, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and

2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II

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.

As of November 6, 2018, seven purported Company shareholders have filed lawsuits under the federal securities laws in the United States District Court for the Southern District of Indiana challenging the adequacy of the disclosures made in the Company's proxy statement in connection with the Merger as discussed in Footnote 11 to the consolidated financial statements. We believe that these complaints are without merit. We cannot predict the outcome of, or estimate the possible loss or range of loss from, these matters.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company’s operating results and financial condition, causing them to be materially adversely affected. Other than the Merger-related risk factors noted below, the Company's risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2017 Form 10-K and are therefore not presented herein.

Risks Associated with Merger

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

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

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

- negative reactions from the financial markets, including declines in the price of the Company's common stock due to the fact that the current price may reflect a market assumption that the Merger will be completed;

- performance shortfalls and missed opportunities as a result of the diversion of the Company's management's attention by the Merger; and

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potential payments by the Company to CenterPoint for damages, or if the Merger Agreement is terminated under certain circumstances, a termination fee of $150 million.

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

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

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

Periodically, the Company has historically purchased shares from the open market to satisfy share requirements associated with the Company’s share-based compensation plans. No such open market purchases were made during the quarter ended September 30, 2018. Under the Merger Agreement, the Company can no longer issue shares of the Company's common stock without the consent of CenterPoint.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

10.1	Second Amendment to Vectren Corporation At-Risk Compensation Plan, as amended and restated May 24, 2016 and further amended effective May 1, 2018. (Filed and designated in Form 8-K dated August 8, 2018, File No. 1-15467, as Exhibit 10.1).
10.2	Term Loan Agreement dated as of September 14, 2018. (Filed and designated in Form 8-K dated September 18, 2018, 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

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 6, 2018	/s/ M. Susan Hardwick M. Susan Hardwick Executive Vice President and Chief Financial Officer (Signing on behalf of the registrant and as Principal Accounting & Financial Officer)