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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): March 28, 2019

CENTERPOINT ENERGY, INC.
(Exact name of registrant as specified in its charter)

Texas	**1-31447**	**74-0694415**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

1111 Louisiana Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (713) 207-1111

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2).

Emerging Growth Company ☐

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 provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 7.01 Regulation FD Disclosure.

Included herein is financial information related to Vectren Utility Holdings, Inc. (“VUHI”) and Southern Indiana Gas & Electric Company (“SIGECO”). SIGECO is a wholly-owned subsidiary of VUHI. VUHI is a wholly-owned subsidiary of Vectren Corporation (“Vectren”). On February 1, 2019, CenterPoint Energy, Inc. (“CenterPoint Energy”) completed its acquisition of Vectren, and Vectren became a wholly-owned subsidiary of CenterPoint Energy.

Exhibits 99.1 and 99.2 to this Current Report on Form 8-K includes audited financial statements for the years ended December 31, 2018 and 2017, for VUHI and SIGECO, respectively. These financial statements are not intended to comply with Regulation S-X or Regulation S-K.

Each of Exhibits 99.1 and 99.2 is furnished, not filed, pursuant to Item 7.01. Accordingly, none of the information will be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), or otherwise subject to the liability of that section, as amended, and the information in Exhibits 99.1 and 99.2 will not be incorporated by reference into any registration statement filed by CenterPoint Energy under the Securities Act of 1933, as amended, unless specifically identified as being incorporated by reference.

Item 9.01 Financial Statements and Exhibits.

Each of Exhibits 99.1 and 99.2 is furnished, not filed, pursuant to Item 7.01. Accordingly, none of the information will be deemed “filed” for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, as amended, and the information in Exhibits 99.1 and 99.2 will not be incorporated by reference into any registration statement filed by CenterPoint Energy under the Securities Act of 1933, as amended, unless specifically identified as being incorporated by reference.

(d) Exhibits.

EXHIBIT NUMBER	EXHIBIT DESCRIPTION
99.1	Reporting Package of Vectren Utility Holdings, Inc.
99.2	Reporting Package of Southern Indiana Gas & Electric Company

SIGNATURE

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

CENTERPOINT ENERGY, INC.

Date: March 28, 2019

By: /s/ Kristie L. Colvin
Kristie L. Colvin
Senior Vice President and Chief Accounting Officer

Exhibit 99.1

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2018

Contents

INDEPENDENT AUDITORS' REPORT

To the Director of Vectren Utility Holdings, Inc.

We have audited the accompanying consolidated financial statements of Vectren Utility Holdings, Inc. and subsidiaries (the "Company") (a wholly owned subsidiary of Vectren Corporation), which comprise the consolidated balance sheets as of December 31, 2018 and 2017, and the related consolidated statements of income, common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Vectren Utility Holdings, Inc. and its subsidiaries as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 28, 2019

VECTREN UTILITY HOLDINGS. INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31, 2018	At December 31, 2017
ASSETS		
Current Assets		
Cash & cash equivalents	$ 22.5	$ 9.8
Accounts receivable - less reserves of $3.7 & $3.9, respectively	112.9	109.5
Accrued unbilled revenues	99.3	123.7
Inventories	92.0	117.5
Recoverable fuel & natural gas costs	6.9	19.2
Prepayments & other current assets	34.4	32.7
Total current assets	**368.0**	**412.4**
Utility Plant		
Original cost	7,528.4	7,015.4
Less: accumulated depreciation & amortization	2,891.7	2,738.7
Net utility plant	**4,636.7**	**4,276.7**
Investments in unconsolidated affiliates	0.2	0.2
Other investments	26.5	26.7
Nonutility plant - net	201.8	198.6
Goodwill	205.0	205.0
Regulatory assets	375.0	314.0
Other assets	60.8	64.2
TOTAL ASSETS	**$5,874.0**	**$5,497.8**

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

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

	At December 31, 2018	At December 31, 2017
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 174.5	$ 221.8
Payables to other Vectren companies	27.6	33.3
Accrued liabilities	180.7	154.0
Short-term borrowings	166.6	179.5
Current maturities of long-term debt	—	100.0
Total current liabilities	**549.4**	**688.6**
Long-Term Debt - Net of Current Maturities	1,779.8	1,479.5
Deferred Credits & Other Liabilities		
Deferred income taxes	489.0	457.5
Regulatory liabilities	941.2	937.2
Deferred credits & other liabilities	227.4	212.2
Total deferred credits & other liabilities	**1,657.6**	**1,606.9**
Commitments & Contingencies (Notes 8-11)		
Common Shareholder's Equity		
Common stock (no par value)	979.2	877.5
Retained earnings	908.0	845.3
Total common shareholder's equity	**1,887.2**	**1,722.8**
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**$5,874.0**	**$5,497.8**

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

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

	Year Ended December 31,		
	2018	2017	2016
OPERATING REVENUES			
Gas utility	$ 857.8	$ 812.7	$ 771.7
Electric utility	582.5	569.6	605.8
Other	0.3	0.3	0.3
Total operating revenues	**1,440.6**	**1,382.6**	**1,377.8**
OPERATING EXPENSES			
Cost of gas sold	316.7	271.5	266.7
Cost of fuel & purchased power	186.2	171.8	183.6
Other operating	355.0	369.3	334.4
Depreciation & amortization	250.1	234.5	219.1
Taxes other than income taxes	63.9	55.9	58.3
Total operating expenses	1,171.9	1,103.0	1,062.1
OPERATING INCOME	**268.7**	**279.6**	**315.7**
Other income - net	36.0	29.5	27.1
Interest expense	81.4	72.6	69.7
INCOME BEFORE INCOME TAXES	**223.3**	**236.5**	**273.1**
Income taxes	32.7	60.7	99.5
NET INCOME	**$ 190.6**	**$ 175.8**	**$ 173.6**

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

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

	Year Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 190.6	$ 175.8	$ 173.6
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	250.1	234.5	219.1
Deferred income taxes & investment tax credits	20.7	45.9	96.7
Provision for uncollectible accounts	6.5	5.7	6.6
Expense portion of pension & postretirement benefit cost	4.2	3.5	4.0
Other non-cash items - net	3.5	2.0	3.5
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenues	14.5	(27.0)	(48.8)
Inventories	25.5	1.5	6.3
Recoverable/refundable fuel & natural gas costs	12.3	10.7	(37.8)
Prepayments & other current assets	(1.7)	5.1	5.0
Accounts payable, including to Vectren companies & affiliated companies	(59.7)	26.2	23.9
Accrued liabilities	26.7	13.9	18.7
Cash to fund pension and postretirement plans	(8.4)	—	(15.0)
Changes in noncurrent assets	(36.9)	(66.0)	(46.5)
Changes in noncurrent liabilities	(24.5)	15.0	(11.9)
Net cash from operating activities	**423.4**	**446.8**	**397.4**
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt, net of issuance costs	299.3	198.5	—
Additional capital contribution	101.7	46.3	31.3
Requirements for:			
Dividends to parent	(127.9)	(123.3)	(116.1)
Retirement of long-term debt	(100.0)	—	(13.0)
Net change in short-term borrowings	(12.9)	(14.9)	179.9
Net cash from financing activities	**160.2**	**106.6**	**82.1**
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from other investing activities	—	2.7	15.3
Requirements for:			
Capital expenditures, excluding AFUDC equity	(570.9)	(554.2)	(496.6)
Other costs	—	(2.4)	—
Changes in restricted cash	—	0.9	5.0
Net cash from investing activities	**(570.9)**	**(553.0)**	**(476.3)**
Net change in cash & cash equivalents	12.7	0.4	3.2
Cash & cash equivalents at beginning of period	9.8	9.4	6.2
Cash & cash equivalents at end of period	$ 22.5	$ 9.8	$ 9.4

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(In millions)

	Common Stock	Retained Earnings	Total
Balance at January 1, 2016	**$ 799.9**	**$ 735.3**	**$1,535.2**
Net income		173.6	173.6
Common stock:			
Additional capital contribution	31.3		31.3
Dividends		(116.1)	(116.1)
Balance at December 31, 2016	**831.2**	**792.8**	**1,624.0**
Net income		175.8	175.8
Common stock:			
Additional capital contribution	46.3		46.3
Dividends		(123.3)	(123.3)
Balance at December 31, 2017	**877.5**	**845.3**	**1,722.8**
Net income		190.6	190.6
Common stock:			
Additional capital contribution	101.7		101.7
Dividends		(127.9)	(127.9)
Balance at December 31, 2018	**$ 979.2**	**$ 908.0**	**$1,887.2**

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

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000, to serve as the intermediate holding company for Vectren Corporation's (Vectren or the Company's parent) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren Energy Delivery of Indiana - North), Southern Indiana Gas and Electric Company (SIGECO or Vectren Energy Delivery of Indiana - South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Herein, 'the Company' may also refer to Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Inc. and/or Vectren Energy Delivery of Ohio, Inc. The Company also has other assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana, and was organized on June 10, 1999. Both Vectren and the Company are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 599,200 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 146,300 electric customers and approximately 111,900 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 320,100 natural gas customers located near Dayton in west-central Ohio.

Merger with CenterPoint Energy, Inc.

On February 1, 2019, Vectren completed the previously announced merger with CenterPoint Energy, Inc., a Texas corporation ("CenterPoint"). In accordance with the Merger Agreement, a wholly owned subsidiary of CenterPoint merged with and into Vectren (the "Merger"), with Vectren surviving as a wholly owned subsidiary of CenterPoint. Vectren's shareholders received $72.00 plus a dividend of $0.41145 in cash for each share of common stock. In addition, all unvested share based compensation awards became fully vested upon close of the transaction, and were either paid out in cash or deferred into a deferred compensation plan. The total purchase price was approximately $6 billion.

The merger was subject to the approvals, orders, or waivers of various government agencies, including the FERC, Federal Communications Commission, Federal Trade Commission, the IURC, and PUCO. Approvals were obtained from all agencies subject to several conditions. The Company does not believe that the conditions set forth in the various regulatory orders approving the merger will have a material impact on its operations or financial results.

2. Summary of Significant Accounting Policies

In applying its accounting policies, the Company makes judgments, assumptions, and estimates that affect the amounts reported in these consolidated financial statements and related footnotes. Examples of transactions for which estimation techniques are used include valuing deferred tax obligations, unbilled revenue, uncollectible accounts, regulatory assets and liabilities, asset retirement obligations, and derivatives and other financial instruments. Estimates also impact the depreciation of utility and nonutility plant and the testing of goodwill and other assets for impairment. Recorded estimates are revised when better information becomes available or when actual amounts can be determined. Actual results could differ from current estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, after appropriate elimination of intercompany transactions.

Subsequent Events Review

Management performs a review of subsequent events for any events occurring after the balance sheet date but prior to the date the financial statements are issued. The Company's management has performed a review of subsequent events through March 28, 2019, the date the financial statements were issued.

Cash & Cash Equivalents

Highly liquid investments with an original maturity of three months or less at the date of purchase are considered cash equivalents. Cash and cash equivalents are stated at cost plus accrued interest to approximate fair value.

Allowance for Uncollectible Accounts

The Company maintains allowances for uncollectible accounts for estimated losses resulting from the inability of its customers to make required payments. The Company estimates the allowance for uncollectible accounts based on a variety of factors including the length of time receivables are past due, the financial health of its customers, unusual macroeconomic conditions, and historical experience. If the financial condition of its customers deteriorates or other circumstances occur that result in an impairment of customers' ability to make payments, the Company records additional allowances as needed.

Inventories

In most circumstances, the Company's inventory components are recorded using an average cost method; however, natural gas in storage at the Company's Indiana utilities is recorded using the Last In – First Out (LIFO) method. Inventory related to the Company's regulated operations is valued at historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

Property, Plant & Equipment

Both the Company's *Utility Plant* and *Nonutility Plant* are stated at historical cost, inclusive of financing costs and direct and indirect construction costs, less accumulated depreciation and when necessary, impairment charges. The cost of renewals and betterments that extend the useful life are capitalized. Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred.

Utility Plant & Related Depreciation

Both the IURC and PUCO allow the Company's utilities to capitalize financing costs associated with *Utility Plant* based on a computed interest cost and a designated cost of equity funds. These financing costs are commonly referred to as AFUDC and are capitalized for ratemaking purposes and for financial reporting purposes instead of amounts that would otherwise be capitalized when acquiring nonutility plant. The Company reports both the debt and equity components of AFUDC in *Other – net* in the *Consolidated Statements of Income*.

When property that represents a retirement unit is replaced or removed, the remaining historical value of such property is charged to *Utility Plant*, with an offsetting charge to *Accumulated depreciation*, resulting in no gain or loss. Costs to dismantle and remove retired property are recovered through the depreciation rates as determined by the IURC and PUCO.

The Company's portion of jointly owned *Utility Plant*, along with that plant's related operating expenses, is presented in these financial statements in proportion to the ownership percentage.

Nonutility Plant & Related Depreciation

The depreciation of *Nonutility Plant* is charged against income over its estimated useful life, using the straight-line method of depreciation. When nonutility property is retired, or otherwise disposed of, the asset and accumulated depreciation are removed, and the resulting gain or loss is reflected in income, typically impacting operating expenses.

Impairment Reviews

Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate the carrying amount may be impaired. This impairment review involves the comparison of an asset's (or group of assets') carrying value to the estimated future cash flows the asset (or asset group) is expected to generate over a remaining life. If this evaluation were to conclude the carrying value is impaired, an impairment charge would be recorded based on the difference between the carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations.

Goodwill

Goodwill recorded on the *Consolidated Balance Sheets* results from business acquisitions and is based on a fair value allocation of the businesses' purchase price at the time of acquisition. Goodwill is charged to expense only when it is impaired. The Company tests its goodwill for impairment at an operating segment level because the components within the segments are similar. These tests are performed at least annually and at the beginning of each year. Impairment reviews consist of a comparison of fair value to the carrying amount. If the fair value is less than the carrying amount, an impairment loss is recognized in operations. No goodwill impairments have been recorded during the periods presented.

Regulation

Retail public utility operations affecting Indiana customers are subject to regulation by the IURC, and retail public utility operations affecting Ohio customers are subject to regulation by the PUCO. The Company's accounting policies give recognition to the ratemaking and accounting practices authorized by these agencies.

Refundable or Recoverable Gas Costs & Cost of Fuel & Purchased Power

All metered gas rates in Indiana contain a gas cost adjustment clause that allows the Company to charge for changes in the cost of purchased gas. Metered electric rates contain a fuel adjustment clause that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to a variable benchmark based on NYMEX natural gas prices, is also recovered through regulatory proceedings. The Company records any under-or-over- recovery resulting from gas and fuel adjustment clauses each month in revenues. A corresponding asset or liability is recorded until the under-or-over-recovery is billed or refunded to utility customers. The cost of gas sold is charged to operating expense as delivered to customers, and the cost of fuel and purchased power for electric generation is charged to operating expense when consumed.

Regulatory Assets & Liabilities

Regulatory assets represent certain incurred costs, which will result in probable future cash recoveries from customers through the ratemaking process. Regulatory liabilities represent probable expenditures by the Company for removal costs or future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. The Company continually assesses the recoverability of costs recognized as regulatory assets and liabilities and the ability to recognize new regulatory assets and liabilities associated with its regulated utility operations. Given the current regulatory environment in its jurisdictions, the Company believes such accounting is appropriate.

The Company collects an estimated cost of removal of its utility plant through depreciation rates established in regulatory proceedings. The Company records amounts expensed in advance of payments as a *Regulatory liability* because the liability does not meet the threshold of an asset retirement obligation.

Asset Retirement Obligations

A portion of removal costs related to interim retirements of gas utility pipeline and electric utility poles, certain asbestos-related issues, and reclamation activities meet the definition of an asset retirement obligation (ARO). The Company records the fair value of a liability for a legal ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. The liability is accreted, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company settles the obligation for its recorded amount or incurs a gain or loss. To the extent regulation is involved, regulatory assets and liabilities result when accretion and amortization is adjusted to match rates established by regulators and any gain or loss is subject to deferral.

Energy Contracts & Derivatives

The Company will periodically execute derivative contracts in the normal course of operations while buying and selling commodities to be used in operations, optimizing its generation assets, and managing risk. A derivative is recognized on the balance sheet as an asset or liability measured at its fair market value and the change in the derivative's fair market value depends on the intended use of the derivative and resulting designation.

When an energy contract that is a derivative is designated and documented as a normal purchase or normal sale (NPNS), it is exempt from mark-to-market accounting. Such energy contracts include Real Time and Day Ahead purchase and sale contracts with the MISO, certain natural gas purchases, and wind farm and other electric generating contracts.

When the Company engages in energy contracts and financial contracts that are derivatives and are not subject to the NPNS or other exclusions, such contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and when the contracts are expected to be settled. Contracts and any associated collateral with counter-parties subject to master netting arrangements are presented net in the *Consolidated Balance Sheets*. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to regulatory accounting treatment. The offset to contracts affected by regulatory accounting treatment, which include most of the Company's executed energy and financial contracts, are marked to market as a regulatory asset or liability. Market value for derivative contracts is determined using quoted market prices from independent sources or from internal models. As of and for the periods presented, derivative activity is not material to these financial statements.

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, typically at a point in time, resulting in revenue being recognized at a single point in time based upon the delivery of services to customers.

MISO Transactions

With the IURC's approval, the Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electrical transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities as well as other utilities in the region. The Company is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded in *Cost of fuel & purchased power* and net sales in a single hour are recorded in *Electric utility revenues*. On occasion, prior period transactions are resettled outside the routine process due to a change in the MISO's tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

The Company also receives transmission revenue that results from other members' use of the Company's transmission system. These revenues are also included in *Electric utility revenues.* Generally, these transmission revenues along with costs charged by the MISO are considered components of base rates and any variance from that included in base rates is recovered from / refunded to retail customers through tracking mechanisms.

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 received as a component of operating revenues, which totaled $31.1 million in 2018, $29.1 million in 2017, and $28.3 million in 2016. Expense associated with excise and utility receipts taxes are recorded as a component of *Taxes other than income taxes*.

Operating Segments

The Company's chief operating decision maker is the Chief Executive Officer. The Company uses net income calculated in accordance with generally accepted accounting principles as its most relevant performance measure. The Company's operations consist of regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

Fair Value Measurements

Certain assets and liabilities are valued and disclosed at fair value. Nonfinancial assets and liabilities include the initial measurement of an asset retirement obligation or the use of fair value in goodwill, intangible assets, and long-lived assets impairment tests. FASB guidance provides the framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are described as follows:

Level 1 Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets.

Level 2 Inputs to the valuation methodology include

- quoted prices for similar assets or liabilities in active markets;
- quoted prices for identical or similar assets or liabilities in inactive markets;
- inputs other than quoted prices that are observable for the asset or liability;
- inputs that are derived principally from or corroborated by observable market data by correlation or other means.

If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.

Level 3 Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used maximize the use of observable inputs and minimize the use of unobservable inputs.

Other Significant Policies

Included elsewhere in these notes are significant accounting policies related to retirement plans and other postretirement benefits, intercompany allocations and income taxes (Note 6).

3. Revenue

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

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

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

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 14, include: Gas Utility Services and Electric Utility Services.

The Company provides commodity service to customers at rates, charges, and terms and conditions included in tariffs approved by regulators. The Company's utilities bill customers 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 Company' s revenues are not subject to significant returns, refunds, or warranty obligations.

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

(In millions)	Year Ended December 31, 2018
Gas Utility Services	
Residential	$ 575.2
Commercial	196.6
Industrial	78.3
Other	7.7
Total Gas Utility Services	$ 857.8
Electric Utility Services	
Residential	$ 210.2
Commercial	149.3
Industrial	162.1
Other	60.9
Total Electric Utility Services	$ 582.5

Contract Balances

The Company does not have any material contract balances (right to consideration for services already provided or obligations to provide services in the future for consideration already received) as of January 1, 2018 or December 31, 2018. Substantially all the Company's accounts receivable results from contracts with customers.

Remaining Performance Obligations

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

4. Utility & Nonutility Plant

The original cost of *Utility Plant*, together with depreciation rates expressed as a percentage of original cost, follows:

(In millions)	At and For the Year Ended December 31,			
	2018		2017	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$ 4,315.3	3.4%	$ 3,969.6	3.4%
Electric utility plant	2,945.8	3.3%	2,833.5	3.3%
Common utility plant	67.6	3.2%	59.0	3.2%
Construction work in progress	112.6	—	70.7	—
Asset retirement obligations	87.1	—	82.6	—
Total original cost	**$ 7,528.4**		**$ 7,015.4**	

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own a 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common. SIGECO's share of the cost of this unit at December 31, 2018, is $192.1 million with accumulated depreciation totaling $128.5 million. AGC and SIGECO share equally in the cost of operation and output of the unit. SIGECO's share of operating costs is included in *Other operating expenses* in the *Consolidated Statements of Income.*

Nonutility Plant, net of accumulated depreciation and amortization follows:

(In millions)	At December 31, 2018	2017
Computer hardware & software	$161.7	$155.6
Land & buildings	33.3	37.1
All other	6.8	5.9
Nonutility plant - net	**$201.8**	**$198.6**

Nonutility plant is presented net of accumulated depreciation and amortization of $297.7 million and $285.6 million as of December 31, 2018 and 2017, respectively. Depreciable lives range from 6 to15 years for computer hardware & software and 30 to 40 years for buildings. The Company capitalized interest totaling $1.2 million for both years ended December 31, 2018 and 2017.

5. Regulatory Assets & Liabilities

Regulatory Assets

Regulatory assets consist of the following:

(In millions)	At December 31, 2018	2017
Future amounts recoverable from ratepayers related to:		
Net deferred income taxes	$ 6.6	$ 6.2
Asset retirement obligations & other	34.4	24.3
	41.0	30.5
Amounts deferred for future recovery related to:		
Indiana cost recovery riders	97.5	70.0
Ohio cost recovery riders	107.9	72.4
	205.4	142.4
Amounts currently recovered in customer rates related to:		
Indiana authorized trackers	67.2	75.9
Ohio authorized trackers	33.0	28.4
Loss on reacquired debt & hedging costs	21.4	22.7
Deferred coal costs and other	7.0	14.1
	128.6	141.1
Total regulatory assets	**$375.0**	**$314.0**

Of the $129 million currently being recovered in customer rates, no amounts are earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $21 million, is 19 years. The remainder of the regulatory assets are being recovered timely through periodic recovery mechanisms. The Company has rate orders for all deferred costs not yet in rates and therefore believes future recovery is probable.

Regulatory assets for asset retirement obligations, see Note 12 for further discussion, are a result of costs incurred for expected retirement activity for the Company's ash ponds beyond what has been recovered in rates. The Company believes the recovery of these assets are probable as the costs are currently being recovered in rates.

Regulatory Liabilities

At December 31, 2018 and 2017, the Company had regulatory liabilities of approximately $941 million and $937 million, respectively, $502 million and $477 million of which related to cost of removal obligations, and at December 31, 2018 and 2017, $438 million and $459 million, respectively, to deferred taxes. The deferred tax related regulatory liability is primarily the revaluation of deferred taxes at the reduced federal corporate tax rate that was enacted on December 22, 2017. These regulatory liabilities are expected to be refunded to customers over time following regulatory commission approval.

6. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)

VISCO, a wholly owned subsidiary of the Company's parent, provides underground pipeline construction and repair services. VISCO's customers include the Company's utilities and fees incurred by the Company totaled $140.8 million in 2018, $157.1 million in 2017, and $117.8 million in 2016. Amounts owed to VISCO at December 31, 2018 and 2017 are included in *Payables to other Vectren companies.*

Support Services & Purchases

The Company's parent provides corporate and general and administrative services to the Company and allocates certain costs to the Company. These costs are allocated using various allocators, including number of employees, number of customers and/ or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. The Company received corporate allocations totaling $52.7 million, $64.1 million, and $57.6 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Retirement Plans & Other Postretirement Benefits

At December 31, 2018, the Company's parent maintains three qualified defined benefit pension plans (Vectren Corporation Non- Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The pension and SERP plans are closed to new participants. The defined benefit pension plans and postretirement benefit plan, which cover the Company's eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The Company's current and former employees comprise the vast majority of the participants and retirees covered by these plans.

The Company's parent satisfies the future funding requirements for funded plans and the payment of benefits for unfunded plans from general corporate assets and, as necessary, relies on the Company to support the funding of these obligations. However, the Company has no contractual funding obligation to the plans. In 2018, the Company contributed $3.5 million to the Company's parent for its defined benefit pension plans. The Company made no contributions to the Company's parent in 2017. The combined funded status of Vectren's defined benefit pension plans was approximately 89 percent and 92 percent at December 31, 2018 and December 31, 2017, respectively.

The Company's parent allocates retirement plan and other postretirement benefit plan periodic cost calculated pursuant to US GAAP to its subsidiaries, which is also how the Company's rate regulated utilities recover retirement plan periodic costs through base rates. Periodic costs are charged to the Company following a labor cost allocation methodology and results in retirement costs being allocated to both operating expense and capital projects. For the years ended December 31, 2018, 2017 and 2016, costs totaling $8.2 million, $8.2 million and $6.1 million, respectively, were charged to the Company.

Any difference between the Company's funding requirements to the Company's parent and allocated periodic costs is recognized by the Company as an intercompany asset or liability. The allocation methodology to determine the intercompany funding requirements from the subsidiaries to Vectren is consistent with FASB guidance related to "multiemployer" benefit accounting. Neither plan assets nor plan obligations as calculated pursuant to GAAP by the Company's parent are allocated to individual subsidiaries.

As of December 31, 2018 and 2017, the Company has $56.8 million, and $61.3 million, respectively, included in *Other assets* representing defined benefit funding by the Company to the Company's parent that is yet to be reflected in costs. As of December 31, 2018 and 2017, the Company has $42.3 million and $47.0 million, respectively, included in *Deferred credits & other liabilities* representing costs related to other postretirement benefits charged to the Company that is yet to be funded to the Company's parent. The Company's labor allocation methodology is used to compute the Company's funding of the defined benefit retirement and other postretirement plans to the Company's parent, which is consistent with the regulatory ratemaking processes of the Company's subsidiaries.

Share-Based Incentive Plans & Deferred Compensation Plans

The Company does not have share-based compensation plans separate from the Company's parent. The Company recognizes its allocated portion of costs related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash that liability is pushed down to the Company. As of December 31, 2018 and 2017, $63.4 million and $55.7 million, respectively, is included in *Accrued liabilities and Deferred credits & other liabilities* and represents obligations that are yet to be funded to the Company's parent. Subsequent to the February 1, 2019 completion of the Merger, and pursuant to the Merger Agreement, all the Company's parent's share-based awards have been settled and a majority of its deferred compensation liabilities have been settled.

Income Taxes

The Company does not file federal or state income tax returns separate from those filed by its parent, Vectren Corporation. The Company's parent files a consolidated U.S. federal income tax return, and Vectren and/or certain of its subsidiaries file income tax returns in various states. Pursuant to a tax sharing agreement and for financial reporting purposes, Vectren subsidiaries record income taxes on a separate company basis. The Company's allocated share of tax effects resulting from it being a part of this consolidated tax group are recorded at the parent company level. Current taxes payable/receivable are settled with the Company's parent in cash quarterly and after filing the consolidated federal and state income tax returns.

Deferred income taxes are provided for temporary differences between the tax basis (adjusted for related unrecognized tax benefits, if any) of an asset or liability and its reported amount in the financial statements. Deferred tax assets and liabilities are computed based on the currently-enacted statutory income tax rates that are expected to be applicable when the temporary differences are scheduled to reverse. The Company's rate-regulated utilities recognize regulatory liabilities for deferred taxes provided in excess of the current statutory tax rate and regulatory assets for deferred taxes provided at rates less than the current statutory tax rate. Such tax-related regulatory assets and liabilities are reported at the revenue requirement level and amortized to income as the related temporary differences reverse, generally over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that the deferred tax assets will be realized.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company reports interest and penalties associated with unrecognized tax benefits within *Income taxes* in the *Consolidated Statements of Income* and reports tax liabilities related to unrecognized tax benefits as part of *Deferred credits & other liabilities*.

Investment tax credits (ITCs) are deferred and amortized to income over the approximate lives of the related property. Production tax credits (PTCs) are recognized as energy is generated and sold based on a per kilowatt hour rate prescribed in applicable federal and state statutes.

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 are 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 under Section 118 of the IRC regarding taxability of contributions made by government or civic groups.

Consolidated results reflect a net tax benefit of $23.2 million for the period ending December 31, 2017 from the enactment of the TCJA. This benefit is associated with the impact of the corporate rate reduction on the Company's deferred income tax balances related to assets which are not included in customer rates, such as goodwill associated with past acquisitions. In addition, the reduction in the federal corporate rate resulted in $333.4 million in excess federal deferred income taxes, which resulted in a regulatory liability of $458.6 million after gross-up.

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 liabilities to record all estimated impacts of tax reform starting January 1, 2018. As of December 31, 2018, the Company has established $39.1 million in liabilities associated with the other impacts of tax reform, including $10.3 million in *Regulatory Liabilities* and $28.8 million in *Accrued Liabilities.*

In Indiana, 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. The refund of excess deferred taxes and regulatory liabilities commenced in November 2018 for the Company's Indiana electric customers and in January 2019 for the Company's Indiana gas customers.

In Ohio, the initial rate reduction to the Company's current rates and charges will be effective upon conclusion of its pending base rate case filed where an order is expected later in 2019. In January 2019, the Company filed an application with PUCO requesting authority to implement a rider to flow back to customers the tax benefits realized under the TCJA, including the refund of excess deferred taxes and regulatory liabilities.

The components of income tax expense and amortization of investment tax credits follow:

	Year Ended December 31,		
(In millions)	2018	2017	2016
Current:			
Federal	$25.4	$10.0	$ (1.4)
State	3.8	4.8	4.2
Total current taxes	**29.2**	**14.8**	**2.8**
Deferred:			
Federal	(1.2)	43.9	93.5
State	1.3	2.4	3.7
Total deferred taxes	**0.1**	**46.3**	**97.2**
Net investment tax credit deferred / (amortized)	3.4	(0.4)	(0.5)
Total income tax expense	**$32.7**	**$60.7**	**$99.5**

A reconciliation of the federal statutory rate to the effective income tax rate follows:

	Year Ended December 31,		
	2018	2017	2016
Statutory rate	21.0%	35.0%	35.0%
Federal tax law change impacts	(8.0)	(9.8)	—
State and local taxes-net of federal benefit	2.8	2.8	2.6
All other - net	(1.2)	(2.3)	(1.2)
Effective tax rate	**14.6%**	**25.7%**	**36.4%**

Significant components of the net deferred tax liability follow:

(In millions)	At December 31, 2018	2017
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$ 548.7	$ 537.2
Regulatory assets recoverable through future rates	8.1	7.9
Alternative minimum tax carryforward	—	(12.2)
Employee benefit obligations	(5.8)	(0.3)
U.S. federal charitable contributions carryforwards	(4.5)	(6.2)
Regulatory liabilities to be settled through future rates	(104.6)	(116.2)
Deferred fuel costs	14.5	16.2
Other – net	32.6	31.1
Net noncurrent deferred tax liability	$ 489.0	$ 457.5

At December 31, 2018 and 2017, investment tax credits totaling $4.6 million and $1.2 million, respectively, are included in *Deferred credits & other liabilities*. At December 31, 2018, the Company has no alternative minimum tax carryforwards. The TCJA eliminated the alternative minimum tax after 2017. Pursuant to the TCJA, the Company will be able to recover its alternative minimum tax carryforwards created in 2017 and prior in future periods.

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The net liability on the *Consolidated Balance Sheet* for unrecognized tax benefits inclusive of interest and penalties totaled $1.7 million and $1.3 million, respectively, at December 31, 2018 and 2017.

The Company's parent and/or certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) is currently examining Vectren's U.S. federal income tax return for tax year December 31, 2016. The State of Indiana, Vectren's primary state tax jurisdiction, is currently examining Vectren's consolidated state returns for December 31, 2015 through 2017 and has previously concluded examinations of state income tax returns for tax years through December 31, 2011. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2015 except to the extent of refunds claimed on amended tax returns. The statutes of limitations for assessment of the 2013 tax year related to the amended federal return will expire in 2020. The statutes of limitations for assessment of the 2012 through 2014 tax years related to the amended Indiana income tax returns will expire in 2019 through 2020.

7. Borrowing Arrangements

Long-Term Debt

Long-term senior unsecured obligations and first mortgage bonds outstanding by subsidiary follow:

(In millions)	At December 31, 2018	At December 31, 2017
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2018, 5.75%	$ —	$ 100.0
2020, 6.28%	100.0	100.0
2021, 4.67%	55.0	55.0
2023, 3.72%	150.0	150.0
2026, 5.02%	60.0	60.0
2028, 3.20%	45.0	45.0
2032, 3.26%	100.0	100.0
2035, 6.10%	75.0	75.0
2035, 3.90%	25.0	25.0
2041, 5.99%	35.0	35.0
2042, 5.00%	100.0	100.0
2043, 4.25%	80.0	80.0
2045, 4.36%	135.0	135.0
2047, 3.93%	100.0	100.0
2055, 4.51%	40.0	40.0
Variable Rate Term Loans		
2020, current adjustable rate, 3.20%	300.0	—
Total Utility Holdings	**1,400.0**	**1,200.0**
SIGECO		
First Mortgage Bonds		
2022, 2013 Series C, current adjustable rate 2.75%, tax exempt	4.6	4.6
2024, 2013 Series D, current adjustable rate 2.75%, tax exempt	22.5	22.5
2025, 2014 Series B, current adjustable rate 2.75%, tax-exempt	41.3	41.3
2029, 1999 Series, 6.72%	80.0	80.0
2037, 2013 Series E, current adjustable rate 2.75%, tax exempt	22.0	22.0
2038, 2013 Series A, current adjustable rate 2.75%, tax exempt	22.2	22.2
2043, 2013 Series B, current adjustable rate 2.75%, tax exempt	39.6	39.6
2044, 2014 Series A, 4.00%, tax exempt	22.3	22.3
2055, 2015 Series Mt. Vernon, 2.375%, tax-exempt	23.0	23.0
2055, 2015 Series Warrick County, 2.375%, tax-exempt	15.2	15.2
Total SIGECO	**292.7**	**292.7**
Indiana Gas		
Fixed Rate Senior Unsecured Notes		
2025, Series E, 6.53%	10.0	10.0
2027, Series E, 6.42%	5.0	5.0
2027, Series E, 6.68%	1.0	1.0
2027, Series F, 6.34%	20.0	20.0
2028, Series F, 6.36%	10.0	10.0
2028, Series F, 6.55%	20.0	20.0
2029, Series G, 7.08%	30.0	30.0
Total Indiana Gas	**96.0**	**96.0**
Total long-term debt outstanding	**1,788.7**	**1,588.7**
Current maturities of long-term debt	—	(100.0)
Debt issuance costs	(8.4)	(8.6)
Unamortized debt premium & discount - net	(0.5)	(0.6)
Total long-term debt-net	**$1,779.8**	**$1,479.5**

Term Loan

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 the remaining $50 million was drawn on December 14, 2018. Proceeds from the term loan were 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 ranging from 70 to 90 basis points depending on Utility Holdings' credit rating. The current spread is 70 basis points and such spread remains unchanged by recent actions taken by rating agencies. In addition, the term loan contains a provision that should Utility Holdings or any of its subsidiaries execute certain capital market transactions, and subject to certain other conditions, the outstanding balance is subject to mandatory prepayment. The term loan is jointly and severally guaranteed by Utility Holdings' wholly-owned operating companies, SIGECO, Indiana Gas, and VEDO.

Utility Holdings Borrowing Arrangements

The Merger constituted a "Change of Control" under the note agreements pursuant to which Senior Notes executed by Utility Holdings in an aggregate principal amount of $1.025 billion were executed. At December 31, 2018, the prepayment offer was accepted on $568 million of Utility Holdings notes. At merger close, CenterPoint loaned Utility Holdings the proceeds necessary to make the prepayment at the same interest rate and term as the notes being prepaid. The CenterPoint notes are not guaranteed by Utility Holdings' subsidiaries.

Pursuant to the Company's short-term credit facility the Merger represented an event of default. However, the banking partner in the facility waived the event of default.

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

Mandatory Tenders

At December 31, 2018, certain series of SIGECO bonds, aggregating $185.7 million are subject to mandatory tenders prior to the bonds' final maturities. $38.2 million will be tendered in 2020 and $147.5 million will be tendered in 2023.

Call Options

At December 31, 2018, certain series of SIGECO bonds may be called at SIGECO's option. $22.3 million is callable in 2019.

Future Long-Term Debt Sinking Fund Requirements and Maturities

The annual sinking fund requirement of SIGECO's first mortgage bonds is 1 percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. SIGECO met the 2018 sinking fund requirement by this means and, expects to also meet this requirement in 2019 in this manner. Accordingly, the sinking fund requirement is excluded from *Current liabilities* in the *Consolidated Balance Sheets*. At December 31, 2018, $1.6 billion of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture. SIGECO's gross utility plant balance subject to the Mortgage Indenture approximated $3.6 billion at December 31, 2018.

Consolidated maturities of long-term debt during the years following 2018 (in millions) are $400.0 in 2020, $55.0 in 2021, $4.6 in 2022, $150.0 in 2023, and $1,170.2 thereafter. There are no maturities of long-term debt in 2019.

Debt Guarantees

The Company's outstanding long-term and short-term debt is jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The Company's long-term debt and short-term debt outstanding at December 31, 2018, totaled $1.4 billion and $167 million, respectively.

Covenants

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 December 31, 2018, the Company was in compliance with all debt covenants.

Short-Term Borrowings

At December 31, 2018, the Company had $400 million of short-term borrowing capacity. The Company's credit agreement is jointly and severally guaranteed by its wholly owned subsidiaries Indiana Gas, SIGECO, and VEDO and is a backup facility for its commercial paper program. The Company's credit facilities are available through July 14, 2022. As reduced by borrowings currently outstanding at December 31, 2018, approximately $233 million was available.

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

(In millions)	2018	2017	2016
Year End			
Balance Outstanding	$166.6	$179.5	$194.4
Weighted Average Interest Rate	3.00%	1.92%	1.05%
Annual Average			
Balance Outstanding	$189.2	$172.4	$ 59.8
Weighted Average Interest Rate	2.30%	1.30%	0.71%
Maximum Month End Balance Outstanding	$262.8	$238.7	$194.4

8. Common Shareholder's Equity

During the years ended December 31, 2018, 2017, and 2016, the Company has cumulatively received additional capital of $179.3 million from the Company's parent, of which $14.3 million was funded by new share issues from its dividend reinvestment plan and $165.0 million was received from the nonutility operations of the Company's parent to fund the Company's capital expenditure program.

9. Commitments & Contingencies

Commitments

Future minimum lease payments required under operating leases that have initial or remaining lease terms in excess of one year during the five years following 2018 and thereafter (in millions) are $0.9 in 2019, $0.7 in 2020, $0.7 in 2021, $0.6 in 2022, $0.5 in 2023, and $0.6 thereafter. Total lease expense, for these types of commitments, (in millions) was $1.0 in 2018, $1.3 in 2017, and $1.1 in 2016.

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

Letters of Credit

The Company, from time to time, through its subsidiaries, issues letters of credit that support consolidated operations. At December 31, 2018, letters of credit outstanding total $8.6 million.

Legal and Regulatory Proceedings

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

10. Gas Rate and Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

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

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

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, 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 nine semi-annual orders which approved the inclusion in rates of approximately $639 million of approved capital investments through June 30, 2018, and approved updates to the seven-year capital investment plan reflecting capital expenditures of approximately $955 million.

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 has removed 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 removed the projects from the plan in accordance with the Opinion when it filed supplemental testimony in its eighth semi-annual TDSIC proceeding on July 25, 2018. The Company does not expect a resulting material impact to results of operations or cash flow from operations.

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. The Company received the IURC Order approving the request for recovery and inclusion in the approved seven-year capital investment plan on December 28, 2017. Approximately $15 million of operating expenses and $12 million of capital investments have been included in the plan over a four-year period beginning in 2017. The Company does not have company-owned storage operations in Ohio.

At December 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $99.4 million and $78.0 million, respectively.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in- service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels. 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 pending base rate case, it requested extension to include investments made starting 2018 through completion of the program, currently estimated by 2023. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $390.9 million as of December 31, 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 $38.1 million and $31.2 million at December 31, 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 December 31, 2018 and December 31, 2017, the Company has regulatory assets totaling $97.6 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 January 4, 2019, the Company, in conjunction with the PUCO Staff, the City of Dayton, Interstate Gas Supply, and the Retail Energy Supply Association, filed a stipulation and recommendation with the PUCO regarding the requested revenue increase. The non-unanimous Stipulation provides for a nearly $22.7 million increase in the base rates and charges for VEDO's distribution business, based on approximately $622 million of rate base and a rate of return of 7.48%. The Stipulation supports the continuation of the straight-fixed-variable rate design for residential customers and expansion to small commercial customers. In addition, the Stipulation supports the extension of the DRR with targeted completion of the accelerated replacement program by 2023, and the continuation of the deferral authority under Ohio House Bill 95 for VEDO's capital expenditure program with a new mechanism to recover future deferrals over the life of the investments. Finally, the Stipulation supports the continuation of the Company's energy efficiency programs through 2020, with a commitment to file for further extension by the end of 2019. The Company expects an order later in 2019.

Pipeline and Hazardous Materials Safety Administration (PHMSA)

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

11. Electric Rate and Regulatory Matters

Electric Requests for Recovery under Senate Bill 560

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

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

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

On 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.

On December 5, 2018, the IURC issued an order (December 2018 order) for the third semi-annual filing approving the inclusion in rates of investments made from November 2017 through April 2018. Through the December 2018 order, approximately $59 million of the approved capital investment plan has been incurred and approved for recovery.

As of December 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $2.2 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.

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 and the remaining investment went into service in 2016. At December 31, 2018 and December 31, 2017, respectively, the Company has regulatory assets totaling $18.6 million and $12.8 million related to depreciation and operating expenses and $6.5 million and $4.7 million 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. On March 17, 2019, the Indiana Court of Appeals issued an order upholding the Commission's Order of the 2016-2017 Energy Efficiency Plan in its entirety.

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. On February 19, 2019, the Indiana Court of Appeals issued an order upholding the Commission's Order of the 2018-2020 Energy Efficiency Plan in its entirety.

For the twelve months ended December 31, 2018, 2017, and 2016, the Company recognized electric utility revenue of $12.3 million, $11.6 million, and $11.1 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 an order authorizing a 10.32 percent base ROE for the first refund period and prospectively from the date of the order. Pursuant to a US Court of Appeals decision in April 2017 which challenged FERC's prior methodology for calculating ROE, in October 2018, the FERC issued an order which established a modified calculation ROE framework. On November 15, 2018, the FERC issued an order reopening the first complaint case taking the modified ROE framework into consideration. The order proposed a preliminary ROE not materially different from the original order and directed participants to submit briefs regarding the proposed approach. Reply comments in response to the order were due in February 2019.

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. Following the resolution of the first complaint case, a base ROE will be established for this period and prospectively from the date of the order.

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, continues to evaluate the potential impacts of the outstanding cases, and does not expect any impact to be material. As of December 31, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.1 million at December 31, 2018.

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 1, 2019, the Company filed its first request for recovery of these investments using the mechanism allowed under Senate Bill 29, with costs of the completed projects totaling approximately $13 million as of December 31, 2018.

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. On March 20, 2019, the IURC approved the settlement agreement in its entirety and granted the Company a CPCN to construct the 50MW universal solar array.

Other Generation Developments

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

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

12. Environmental and 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. 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 December 31, 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.

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. In the case of Vectren's water discharge permits, in 2017 the Indiana Department of Environmental Management (IDEM) issued final renewals for Company's F.B. Culley and A.B. Brown power plants. IDEM agreed that units identified for retirement by December 2023 would not be required to install new treatment technology to meet ELG, and approved a 2020 compliance date for dry bottom ash and a 2023 compliance date for flue gas desulfurization wastewater treatment standards for the remaining coal-fired unit at F.B. Culley.

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

MATS Reconsideration

On December 27, 2018, US EPA proposed to revise the Supplemental Cost Finding for the Mercury and Air Toxics Standards (MATS) rule, as well as the hazardous air pollutants risk and technology review (RTR) required under the CAA. Specifically, the agency proposes to determine that it is not "appropriate and necessary" to regulate hazardous air pollutant emission from power plants under Section 112 of the CAA. Under the proposal, the emission standards and other requirements of the MATS rule, first promulgated in 2012, would remain in place, since EPA is not proposing to remove coal-fired power plants from the list of sources that are regulated under Section 112 of the Act. The Company is in full compliance with MATS and does not anticipate significant impacts or operational changes under this proposal.

Climate Change and Carbon Strategy

Clean Power Plan and ACE Rule

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

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

Impact of Legislative Actions & Other Initiatives

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

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

<u>Manufactured Gas Plants</u>

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 substantially all 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 December 31, 2018 and December 31, 2017, approximately $2.6 million and $2.5 million, respectively of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

13. Fair Value Measurements

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

	At December 31,			
	2018		2017	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,779.8	$1,848.7	$1,579.5	$1,715.2
Short-term borrowings & notes payable	166.6	166.6	179.5	179.5
Cash & cash equivalents	22.5	22.5	9.8	9.8
Natural gas purchase instrument assets (1)	—	—	0.5	0.5
Natural gas purchase instrument liabilities (2)	12.1	12.1	4.5	4.5
Interest rate swap liabilities (3)	0.1	0.1	1.4	1.4

(1) Presented in "Other investments" on the Consolidated Balance Sheets.
(2) Presented in "Accrued liabilities" and "Deferred credits & other liabilities" on the Consolidated Balance Sheets.
(3) Presented in "Deferred credits & other liabilities" on the Consolidated Balance Sheets.

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 four five-year forward purchase arrangements to hedge the variable 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 7, the Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging variability in interest rates. The Company values these contracts using a pricing model that incorporates market-based information, and are classified within Level 2 of the fair value hierarchy.

14. Segment Reporting

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

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

(In millions)	Year Ended December 31, 2018	2017	2016
Revenues			
Gas Utility Services	$ 857.8	$ 812.7	$ 771.7
Electric Utility Services	582.5	569.6	605.8
Other Operations	47.1	45.6	42.2
Eliminations	(46.8)	(45.3)	(41.9)
Total revenues	$1,440.6	$1,382.6	$1,377.8
Profitability Measure - Net Income			
Gas Utility Services	$ 99.3	$ 115.5	$ 76.1
Electric Utility Services	76.2	75.2	84.7
Other Operations	15.1	(14.9)	12.8
Total net income	$ 190.6	$ 175.8	$ 173.6
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Gas Utility Services	$ 130.1	$ 118.9	$ 108.1
Electric Utility Services	91.8	89.5	87.1
Other Operations	28.2	26.1	23.9
Total depreciation & amortization	$ 250.1	$ 234.5	$ 219.1
Interest Expense			
Gas Utility Services	$ 49.3	$ 43.0	$ 40.1
Electric Utility Services	26.7	25.8	27.0
Other Operations	5.4	3.8	2.6
Total interest expense	$ 81.4	$ 72.6	$ 69.7
Income Taxes			
Gas Utility Services	$ 13.6	$ 25.4	$ 47.1
Electric Utility Services	21.7	41.4	50.1
Other Operations	(2.6)	(6.1)	2.3
Total income taxes	$ 32.7	$ 60.7	$ 99.5
Capital Expenditures			
Gas Utility Services	$ 377.2	$ 391.4	$ 358.5
Electric Utility Services	163.6	105.3	106.4
Other Operations	42.8	60.1	39.0
Non-cash costs & changes in accruals	(12.7)	(2.6)	(7.3)
Total capital expenditures	$ 570.9	$ 554.2	$ 496.6

(In millions)	At December 31, 2018	2017	2016
Assets			
Gas Utility Services	$3,794.2	$3,457.8	$3,091.0
Electric Utility Services	1,950.0	1,820.3	1,788.4
Other Operations, net of eliminations	129.8	219.7	161.5
Total assets	$5,874.0	$5,497.8	$5,040.9

15. Additional Balance Sheet & Operational Information

Inventories consist of the following:

(In millions)	At December 31, 2018	2017
Gas in storage – at LIFO cost	$36.0	$ 36.0
Materials & supplies	38.0	37.0
Coal & oil for electric generation - at average cost	16.6	43.1
Other	1.4	1.4
Total inventories	**$92.0**	**$117.5**

Based on the average cost of gas purchased during December 2018, the cost of replacing inventories carried at LIFO cost was greater than carrying value at December 31, 2018 by $2.0 million. Based on the average cost of gas purchased during December 2017, the cost of replacing inventories carried at LIFO cost was less than the carrying value at December 31, 2017 by $2.0 million.

Prepayments & other current assets in the Consolidated Balance Sheets consist of the following:

(In millions)	At December 31, 2018	2017
Prepaid gas delivery service	$23.2	$26.6
Prepaid taxes	4.0	2.6
Other prepayments & current assets	7.2	3.5
Total prepayments & other current assets	**$34.4**	**$32.7**

Other investments in the Consolidated Balance Sheets consist of the following:

(In millions)	At December 31, 2018	2017
Cash surrender value of life insurance policies	$25.6	$25.4
Other	0.9	1.3
Total other investments	**$26.5**	**$26.7**

Accrued liabilities in the Consolidated Balance Sheets consist of the following:

(In millions)	At December 31, 2018	2017
Refunds to customers & customer deposits	$ 83.9	$ 51.4
Accrued taxes	44.7	55.8
Accrued interest	15.7	17.9
Accrued salaries & other	36.4	28.9
Total accrued liabilities	**$180.7**	**$154.0**

Asset retirement obligations included in *Deferred credits and other liabilities* in the Consolidated Balance Sheets roll forward as follows:

(In millions)	2018	2017
Asset retirement obligation, January 1	$106.9	$106.6
Accretion	4.5	4.3
Changes in estimates, net of cash payments	4.5	(4.0)
Asset retirement obligation, December 31	**$115.9**	**$106.9**

Other – net in the Consolidated Statements of Income consists of the following:

	Year Ended December 31,		
(In millions)	2018	2017	2016
AFUDC - borrowed funds	$29.7	$24.8	$20.3
AFUDC - equity funds	3.4	2.6	2.2
Nonutility plant capitalized interest	1.2	1.2	1.0
Interest income	—	—	0.3
Other income	1.7	2.0	2.5
Total other – net	**$36.0**	**$30.6**	**$26.3**

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2018	2017	2016
Cash paid (received) for:			
Interest	$83.7	$71.2	$69.6
Income taxes	44.4	(6.1)	6.7

As of December 31, 2018 and 2017, the Company has accruals related to utility and nonutility plant purchases totaling approximately $35.9 million and $27.5 million, respectively.

16. Subsidiary Guarantor & Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO, are guarantors of the Company's $400 million in short-term credit facilities, of which $167 million was outstanding at December 31, 2018, and the Company's $1.4 billion in unsecured senior notes outstanding at December 31, 2018. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. However, it does have operations other than those of the subsidiary guarantors. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors, which are wholly owned, separate from the parent company's operations is required. Following are consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

Consolidating Statement of Income for the year ended December 31, 2018 (in millions):

	Subsidiary Guarantors	Parent Company	Reclassifications & Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 857.8	$ —	$ —	$ 857.8
Electric utility	582.5	—	—	582.5
Other	—	47.1	(46.8)	0.3
Total operating revenues	**1,440.3**	**47.1**	**(46.8)**	**1,440.6**
OPERATING EXPENSES				
Cost of gas sold	316.7	—	—	316.7
Cost of fuel & purchased power	186.2	—	—	186.2
Other operating	400.9	—	(45.9)	355.0
Depreciation & amortization	222.4	27.6	0.1	250.1
Taxes other than income taxes	62.0	1.8	0.1	63.9
Total operating expenses	1,188.2	29.4	(45.7)	1,171.9
OPERATING INCOME	**252.1**	**17.7**	**(1.1)**	**268.7**
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	175.5	(175.5)	—
Other – net	34.8	57.5	(56.3)	36.0
Total other income (expense)	34.8	233.0	(231.8)	36.0
Interest expense	76.0	62.8	(57.4)	81.4
INCOME BEFORE INCOME TAXES	**210.9**	**187.9**	**(175.5)**	**223.3**
Income taxes	35.4	(2.7)	—	32.7
NET INCOME	**$ 175.5**	**$ 190.6**	**$ (175.5)**	**$ 190.6**

Consolidating Statement of Income for the year ended December 31, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Reclassifications & Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 812.7	$ —	$ —	$ 812.7
Electric utility	569.6	—	—	569.6
Other	—	45.6	(45.3)	0.3
Total operating revenues	**1,382.3**	**45.6**	**(45.3)**	**1,382.6**
OPERATING EXPENSES				
Cost of gas sold	271.5	—	—	271.5
Cost of fuel & purchased power	171.8	—	—	171.8
Other operating	377.5	35.7	(43.9)	369.3
Depreciation & amortization	208.4	26.0	0.1	234.5
Taxes other than income taxes	53.8	2.0	0.1	55.9
Total operating expenses	1,083.0	63.7	(43.7)	1,103.0
OPERATING INCOME	**299.3**	**(18.1)**	**(1.6)**	**279.6**
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	190.7	(190.7)	—
Other – net	27.1	50.3	(47.9)	29.5
Total other income (expense)	27.1	241.0	(238.6)	29.5
Interest expense	68.8	53.3	(49.5)	72.6
INCOME BEFORE INCOME TAXES	**257.6**	**169.6**	**(190.7)**	**236.5**
Income taxes	66.9	(6.2)	—	60.7
NET INCOME	**$ 190.7**	**$ 175.8**	**$ (190.7)**	**$ 175.8**

Consolidating Statement of Income for the year ended December 31, 2016 (in millions):

	Subsidiary Guarantors	Parent Company	Reclassifications & Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 771.7	$ —	$ —	$ 771.7
Electric utility	605.8	—	—	605.8
Other	—	42.2	(41.9)	0.3
Total operating revenues	**1,377.5**	**42.2**	**(41.9)**	**1,377.8**
OPERATING EXPENSES				
Cost of gas sold	266.7	—	—	266.7
Cost of fuel & purchased power	183.6	—	—	183.6
Other operating	374.8	—	(40.4)	334.4
Depreciation & amortization	195.2	23.8	0.1	219.1
Taxes other than income taxes	56.8	1.5	—	58.3
Total operating expenses	1,077.1	25.3	(40.3)	1,062.1
OPERATING INCOME	**300.4**	**16.9**	**(1.6)**	**315.7**
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	160.8	(160.8)	—
Other – net	24.8	48.3	(46.0)	27.1
Total other income (expense)	24.8	209.1	(206.8)	27.1
Interest expense	67.2	50.1	(47.6)	69.7
INCOME BEFORE INCOME TAXES	**258.0**	**175.9**	**(160.8)**	**273.1**
Income taxes	97.2	2.3	—	99.5
NET INCOME	**$ 160.8**	**$ 173.6**	**$ (160.8)**	**$ 173.6**

Consolidating Balance Sheet as of December 31, 2018 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Assets				
Cash & cash equivalents	$ 13.0	$ 9.5	$ —	$ 22.5
Accounts receivable - less reserves	112.7	0.2	—	112.9
Intercompany receivables	98.8	143.6	(242.4)	—
Accrued unbilled revenues	99.3	—	—	99.3
Inventories	92.0	—	—	92.0
Recoverable fuel & natural gas costs	6.9	—	—	6.9
Prepayments & other current assets	32.2	3.9	(1.7)	34.4
Total current assets	**454.9**	**157.2**	**(244.1)**	**368.0**
Utility Plant				
Original cost	7,528.4	—	—	7,528.4
Less: accumulated depreciation & amortization	2,891.7	—	—	2,891.7
Net utility plant	**4,636.7**	**—**	**—**	**4,636.7**
Investments in consolidated subsidiaries	—	2,001.8	(2,001.8)	—
Notes receivable from consolidated subsidiaries	—	1,220.0	(1,220.0)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	26.1	0.4	—	26.5
Nonutility plant - net	1.6	200.2	—	201.8
Goodwill - net	205.0	—	—	205.0
Regulatory assets	360.4	14.6	—	375.0
Other assets	59.3	1.5	—	60.8
TOTAL ASSETS	**$5,744.2**	**$3,595.7**	**$ (3,465.9)**	**$ 5,874.0**

LIABILITIES & SHAREHOLDER’S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Liabilities				
Accounts payable	$ 170.2	$ 4.3	$ —	$ 174.5
Intercompany payables	12.0	—	(12.0)	—
Payables to other Vectren companies	27.6	—	—	27.6
Accrued liabilities	168.8	13.6	(1.7)	180.7
Short-term borrowings	—	166.6	—	166.6
Intercompany short-term borrowings	131.6	98.8	(230.4)	—
Total current liabilities	**510.2**	**283.3**	**(244.1)**	**549.4**
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	384.3	1,395.5	—	1,779.8
Long-term debt due to VUHI	1,220.0	—	(1,220.0)	—
Total long-term debt - net	1,604.3	1,395.5	(1,220.0)	1,779.8
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	462.8	26.2	—	489.0
Regulatory liabilities	940.1	1.1	—	941.2
Deferred credits & other liabilities	225.0	2.4	—	227.4
Total deferred credits & other liabilities	1,627.9	29.7	—	1,657.6
Common Shareholder’s Equity				
Common stock (no par value)	1,097.2	979.2	(1,097.2)	979.2
Retained earnings	904.6	908.0	(904.6)	908.0
Total common shareholder’s equity	**2,001.8**	**1,887.2**	**(2,001.8)**	**1,887.2**
TOTAL LIABILITIES & SHAREHOLDER’S EQUITY	**$5,744.2**	**$3,595.7**	**$ (3,465.9)**	**$ 5,874.0**

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

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

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Liabilities				
Accounts payable	$ 179.4	$ 42.4	$ —	$ 221.8
Intercompany payables	8.3	—	(8.3)	—
Payables to other Vectren companies	25.2	8.1	—	33.3
Accrued liabilities	147.7	15.1	(8.8)	154.0
Short-term borrowings	—	179.5	—	179.5
Intercompany short-term borrowings	120.2	—	(120.2)	—
Current maturities of long-term debt	—	100.0	—	100.0
Current maturities of long-term debt due to VUHI	99.0	—	(99.0)	—
Total current liabilities	**579.8**	**345.1**	**(236.3)**	**688.6**
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	384.5	1,095.0	—	1,479.5
Long-term debt due to VUHI	970.7	—	(970.7)	—
Total long-term debt - net	1,355.2	1,095.0	(970.7)	1,479.5
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	455.3	2.2	—	457.5
Regulatory liabilities	936.1	1.1	—	937.2
Deferred credits & other liabilities	210.3	2.0	(0.1)	212.2
Total deferred credits & other liabilities	1,601.7	5.3	(0.1)	1,606.9
Common Shareholder's Equity				
Common stock (no par value)	890.7	877.5	(890.7)	877.5
Retained earnings	850.3	845.3	(850.3)	845.3
Total common shareholder's equity	**1,741.0**	**1,722.8**	**(1,741.0)**	**1,722.8**
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**$5,277.7**	**$3,168.2**	**$ (2,948.1)**	**$ 5,497.8**

Consolidating Statement of Cash Flows for the year ended December 31, 2018 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FROM OPERATING ACTIVITIES	**$ 384.9**	**$ 38.5**	**$ —**	**$ 423.4**
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	248.7	299.3	(248.7)	299.3
Additional capital contribution from parent	206.5	101.7	(206.5)	101.7
Requirements for:				
Dividends to parent	(121.2)	(127.9)	121.2	(127.9)
Retirement of long-term debt	(99.0)	(100.0)	99.0	(100.0)
Net change in intercompany short-term borrowings	11.5	98.7	(110.2)	—
Net change in short-term borrowings	—	(12.9)	—	(12.9)
Net cash from financing activities	**246.5**	**258.9**	**(345.2)**	**160.2**
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	121.2	(121.2)	—
Requirements for:				
Capital expenditures, excluding AFUDC equity	(527.9)	(43.0)	—	(570.9)
Consolidated subsidiary investments	—	(206.5)	206.5	—
Net change in long-term intercompany notes receivable	—	(149.7)	149.7	—
Net change in short-term intercompany notes receivable	(98.7)	(11.5)	110.2	—
Net cash from investing activities	**(626.6)**	**(289.5)**	**345.2**	**(570.9)**
Net change in cash & cash equivalents	4.8	7.9	—	12.7
Cash & cash equivalents at beginning of period	8.2	1.6	—	9.8
Cash & cash equivalents at end of period	$ 13.0	$ 9.5	$ —	$ 22.5

Consolidating Statement of Cash Flows for the year ended December 31, 2017 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FROM OPERATING ACTIVITIES	**$ 398.5**	**$ 48.3**	**$ —**	**$ 446.8**
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	123.9	198.9	(124.3)	198.5
Additional capital contribution from parent	46.3	46.3	(46.3)	46.3
Requirements for:				
Dividends to parent	(73.1)	(123.3)	73.1	(123.3)
Net change in intercompany short-term borrowings	(22.1)	(17.5)	39.6	—
Net change in short-term borrowings	—	(14.9)	—	(14.9)
Net cash from financing activities	**75.0**	**89.5**	**(57.9)**	**106.6**
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	73.1	(73.1)	—
Other investing activities	2.7	—	—	2.7
Requirements for:				
Capital expenditures, excluding AFUDC equity	(491.6)	(62.6)	—	(554.2)
Consolidated subsidiary investments	—	(46.3)	46.3	—
Other costs	(2.4)	—	—	(2.4)
Changes in restricted cash	0.9	—	—	0.9
Net change in long-term intercompany notes receivable	—	(124.3)	124.3	—
Net change in short-term intercompany notes receivable	17.5	22.1	(39.6)	—
Net cash from investing activities	**(472.9)**	**(138.0)**	**57.9**	**(553.0)**
Net change in cash & cash equivalents	0.6	(0.2)	—	0.4
Cash & cash equivalents at beginning of period	7.6	1.8	—	9.4
Cash & cash equivalents at end of period	$ 8.2	$ 1.6	$ —	$ 9.8

Consolidating Statement of Cash Flows for the year ended December 31, 2016 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FROM OPERATING ACTIVITIES	**$ 352.2**	**$ 45.2**	**$ —**	**$ 397.4**
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Long-term debt, net of issuance costs	109.4	—	(109.4)	—
Additional capital contribution from parent	31.3	31.3	(31.3)	31.3
Requirements for:				
Dividends to parent	(82.0)	(116.1)	82.0	(116.1)
Retirement of long-term debt	(13.0)	—	—	(13.0)
Net change in intercompany short-term borrowings	11.9	(33.7)	21.8	—
Net change in short-term borrowings	—	179.9	—	179.9
Net cash from financing activities	**57.6**	**61.4**	**(36.9)**	**82.1**
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	82.0	(82.0)	—
Other investing activities	15.3	—	—	15.3
Requirements for:				
Capital expenditures, excluding AFUDC equity	(461.7)	(34.9)	—	(496.6)
Consolidated subsidiary investments	—	(31.3)	31.3	—
Changes in restricted cash	5.0	—	—	5.0
Net change in long-term intercompany notes receivable	—	(109.4)	109.4	—
Net change in short-term intercompany notes receivable	33.7	(11.9)	(21.8)	—
Net cash from investing activities	**(407.7)**	**(105.5)**	**36.9**	**(476.3)**
Net change in cash & cash equivalents	2.1	1.1	—	3.2
Cash & cash equivalents at beginning of period	5.5	0.7	—	6.2
Cash & cash equivalents at end of period	$ 7.6	$ 1.8	$ —	$ 9.4

17. Impact of Recently Issued Accounting Guidance

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. The Company has adopted the guidance effective January 1, 2019.

ASU 2016-02 includes multiple practical expedients that may be elected but must be elected as a package. These practical expedients allow lessees and lessors to: 1) not reassess expired or existing contracts to determine whether they are subject to lease accounting guidance, (2) not reconsider lease classification at transition, and (3) not evaluate previously capitalized initial direct costs under the revised requirements. The Company has elected to utilize this package of three expedients.

The Company has adopted an accounting policy that exempts leases with terms of less than one year from the recognition requirements of the standard. The ASU also provides lessees the option of electing an accounting policy, by class of underlying asset, in which the lessee may choose not to separate nonlease components from lease components. The Company has adopted this practical expedient for certain classes of leases.

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 has applied 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 has applied the election under 2018-11 to its 2016-02 adoption.

As of December 31, 2018, the Company has reviewed substantially all its leases and related contracts and has completed its preliminary evaluation of the guidance. The population primarily consists of business and office facility leases. While the Company is continuing to evaluate the full impact of the standard on the consolidated financial statements and related disclosures, upon adoption, the Company will recognize right-of-use assets and lease liabilities for leases currently classified as operating leases. 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.

18. Quarterly Financial Data (Unaudited)

Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company's utility operations. Summarized quarterly financial data for 2018 and 2017 follows:

(In millions)	Q1	Q2	Q3	Q4
2018				
Results of Operations:				
Operating revenues	$463.4	$292.7	$282.2	$402.3
Operating income	101.0	39.2	49.8	78.7
Net income	74.3	25.5	33.0	57.8
2017				
Results of Operations:				
Operating revenues	$425.0	$285.9	$279.7	$392.1
Operating income	113.5	49.7	58.0	57.5
Net income	65.9	25.5	30.8	53.6

Exhibit 99.2

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
FINANCIAL STATEMENTS

For the year ended December 31, 2018

Contents

INDEPENDENT AUDITORS' REPORT

To the Director of Southern Indiana Gas & Electric Company:

We have audited the accompanying financial statements of Southern Indiana Gas & Electric Company (the "Company") (a wholly owned subsidiary of Vectren Utility Holdings, Inc.), which comprise the balance sheets as of December 31, 2018 and 2017, and the related statements of income, cash flows, and common shareholder's equity for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Southern Indiana Gas & Electric Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 28, 2019

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
BALANCE SHEETS
(*In thousands*)

	December 31, 2018	December 31, 2017
ASSETS		
Utility Plant		
Original cost	$3,618,332	$3,417,454
Less: accumulated depreciation & amortization	1,595,300	1,527,646
Net utility plant	**2,023,032**	**1,889,808**
Current Assets		
Cash & cash equivalents	2,284	2,275
Notes receivable from Utility Holdings	98,678	—
Accounts receivable - less reserves of $1,831 & $1,967, respectively	45,627	45,641
Receivables from other Vectren companies	126	3
Accrued unbilled revenues	28,256	38,744
Inventories	69,877	93,272
Recoverable fuel & natural gas costs	2,435	9,797
Prepayments & other current assets	6,403	1,674
Total current assets	**253,686**	**191,406**
Investments in unconsolidated affiliates	150	150
Other investments	12,396	12,652
Nonutility plant - net	1,491	1,558
Goodwill - net	5,557	5,557
Regulatory assets	105,822	95,303
Other assets	26,802	28,078
TOTAL ASSETS	**$2,428,936**	**$2,224,512**

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
BALANCE SHEETS
(*In thousands*)

	December 31, 2018	December 31, 2017
LIABILITIES & SHAREHOLDER'S EQUITY		
Common shareholder's equity		
Common stock (no par value)	$ 433,277	$ 313,290
Retained earnings	581,600	557,119
Total common shareholder's equity	**1,014,877**	**870,409**
Long-term debt payable to third parties	288,345	288,517
Long-term debt payable to Utility Holdings - net of current maturities	447,959	333,512
Total long-term debt	**736,304**	**622,029**
Commitments & Contingencies (Notes 6, 8-11)		
Current Liabilities		
Accounts payable	49,673	42,394
Payables to other Vectren companies	11,656	6,034
Accrued liabilities	56,521	50,875
Short-term borrowings payable to Utility Holdings	—	1,718
Current maturities of long-term debt payable to Utility Holdings	—	61,880
Total current liabilities	**117,850**	**162,901**
Deferred Credits & Other Liabilities		
Deferred income taxes	190,077	195,252
Regulatory liabilities	255,991	265,239
Deferred credits & other liabilities	113,837	108,682
Total deferred credits & other liabilities	**559,905**	**569,173**
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**$2,428,936**	**$2,224,512**

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
STATEMENTS OF INCOME
(*In thousands*)

	Year Ended December 31,	
	2018	2017
OPERATING REVENUES		
Electric utility	$582,504	$569,587
Gas utility	100,044	92,396
Total operating revenues	**682,548**	**661,983**
OPERATING EXPENSES		
Cost of fuel & purchased power	186,203	171,794
Cost of gas sold	40,309	33,949
Other operating	203,557	187,812
Depreciation & amortization	104,692	100,792
Taxes other than income taxes	18,784	17,728
Total operating expenses	**553,545**	**512,075**
OPERATING INCOME	**129,003**	**149,908**
Other income – net	7,890	5,539
Interest expense	32,934	31,410
INCOME BEFORE INCOME TAXES	**103,959**	**124,037**
Income taxes	22,454	44,110
NET INCOME	**$ 81,505**	**$ 79,927**

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(*In thousands*)

	Year Ended December 31, 2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 81,505	$ 79,927
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	104,692	100,792
Deferred income taxes & investment tax credits	(6,306)	10,241
Expense portion of pension & postretirement periodic benefit cost	1,899	2,382
Provision for uncollectible accounts	2,150	2,303
Other non-cash charges - net	(251)	710
Changes in working capital accounts:		
Accounts receivable, including due from Vectren companies & accrued unbilled revenues	8,229	(10,059)
Inventories	23,395	(957)
Recoverable/refundable fuel & natural gas costs	7,362	(2,791)
Prepayments & other current assets	(4,828)	3,417
Accounts payable, including to Vectren companies & affiliated companies	10,160	(11,662)
Accrued liabilities	5,536	7,941
Changes in noncurrent assets	(2,338)	(26,097)
Changes in noncurrent liabilities	(17,299)	1,011
Net cash from operating activities	**213,906**	**157,158**
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Capital contribution from Utility Holdings	119,987	—
Long-term debt, net of issuance costs	113,360	29,375
Requirements for:		
Dividends to Utility Holdings	(57,024)	(54,935)
Retirement of long-term debt	(61,880)	—
Net change in short-term borrowings, including from Utility Holdings	(1,718)	1,718
Net cash from financing activities	**112,725**	**(23,842)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	—	2,741
Requirements for capital expenditures, excluding AFUDC equity	(227,944)	(153,710)
Net change in short-term intercompany notes receivable	(98,678)	17,496
Changes in restricted cash	—	933
Net cash from investing activities	**(326,622)**	**(132,540)**
Net change in cash & cash equivalents	9	776
Cash & cash equivalents at beginning of period	2,275	1,499
Cash & cash equivalents at end of period	$ 2,284	$ 2,275

The accompanying notes are an integral part of these financial statements

SOUTHERN INDIANA GAS & ELECTRIC COMPANY
STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(*In thousands*)

	Common Stock	Retained Earnings	Total
Balance at January 1, 2017	**$313,290**	**$532,127**	**$ 845,417**
Net income		79,927	79,927
Common stock:			
Dividends to Utility Holdings		(54,935)	(54,935)
Balance at December 31, 2017	**$313,290**	**$557,119**	**$ 870,409**
Net income		81,505	81,505
Common stock:			
Capital contribution from Utility Holdings	119,987		119,987
Dividends to Utility Holdings		(57,024)	(57,024)
Balance at December 31, 2018	**$433,277**	**$581,600**	**$1,014,877**

The accompanying notes are an integral part of these financial statements

1. Organization and Nature of Operation

Southern Indiana Gas and Electric Company (the Company, or SIGECO), an Indiana corporation, provides energy delivery services to approximately 146,300 electric customers and approximately 111,900 gas customers located near Evansville in southwestern Indiana. Of these customers, approximately 85,200 receive combined electric and gas distribution services. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. SIGECO is a direct, wholly owned subsidiary of Vectren Utility Holdings, Inc. (Utility Holdings or the Company's parent). The Company's parent is a direct, wholly owned subsidiary of Vectren Corporation (Vectren). SIGECO generally does business as Vectren Energy Delivery of Indiana, Inc. Vectren is an energy holding company headquartered in Evansville, Indiana.

Merger with CenterPoint Energy, Inc.

On February 1, 2019, Vectren completed the previously announced merger with CenterPoint Energy, Inc., a Texas corporation ("CenterPoint"). In accordance with the Merger Agreement, a wholly owned subsidiary of CenterPoint merged with and into Vectren (the "Merger"), with Vectren surviving as a wholly owned subsidiary of CenterPoint. The total purchase price was approximately $6 billion.

The merger was subject to the approvals, orders, or waivers of various government agencies, including the FERC, Federal Communications Commission, Federal Trade Commission, the Indiana Utility Regulatory Commission (IURC), and the Public Utilities Commission of Ohio. Approvals were obtained from all agencies subject to several conditions. The Company does not believe that the conditions set forth in the various regulatory orders approving the merger will have a material impact on its operations or financial results.

2. Summary of Significant Accounting Policies

In applying its accounting policies, the Company makes judgments, assumptions, and estimates that affect the amounts reported in these financial statements and related footnotes. Examples of transactions for which estimation techniques are used include valuing deferred tax obligations, unbilled revenue, uncollectible accounts, regulatory assets and liabilities, asset retirement obligations, and derivatives and other financial instruments. Estimates also impact the depreciation of utility and nonutility plant and the testing of goodwill and other assets for impairment. Recorded estimates are revised when better information becomes available or when actual amounts can be determined. Actual results could differ from current estimates.

Subsequent Events Review

Management performs a review of subsequent events for any events occurring after the balance sheet date but prior to the date the financial statements are issued. The Company's management has performed a review of subsequent events through March 28, 2019, the date the financial statements were issued.

Cash & Cash Equivalents

Highly liquid investments with an original maturity of three months or less at the date of purchase are considered cash equivalents. Cash and cash equivalents are stated at cost plus accrued interest to approximate fair value.

Allowance for Uncollectible Accounts

The Company maintains an allowance for uncollectible accounts for estimated losses resulting from the inability of its customers to make required payments. The Company estimates the allowance for uncollectible accounts based on a variety of factors including the length of time receivables are past due, the financial health of its customers, unusual macroeconomic conditions, and historical experience. If the financial condition of its customers deteriorates or other circumstances occur that result in an impairment of customers' ability to make payments, the Company records additional allowance as needed.

Inventories

In most circumstances, the Company's inventory components are recorded using an average cost method; however, natural gas in storage is recorded using the Last In – First Out (LIFO) method. Inventory is valued at historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

Property, Plant & Equipment

Both the Company's *Utility Plant* and *Nonutility Plant* are stated at historical cost, inclusive of financing costs and direct and indirect construction costs, less accumulated depreciation and when necessary, impairment charges. The cost of renewals and betterments that extend the useful life are capitalized. Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred.

Utility Plant & Related Depreciation

The IURC allows the Company to capitalize financing costs associated with *Utility Plant* based on a computed interest cost and a designated cost of equity funds. These financing costs are commonly referred to as AFUDC and are capitalized for ratemaking purposes and for financial reporting purposes instead of amounts that would otherwise be capitalized when acquiring nonutility plant. The Company reports both the debt and equity components of AFUDC in *Other income – net* in the *Statements of Income*.

When property that represents a retirement unit is replaced or removed, the remaining historical value of such property is charged to *Utility Plant*, with an offsetting charge to *Accumulated depreciation*, resulting in no gain or loss. Costs to dismantle and remove retired property are recovered through the depreciation rates as determined by the IURC.

The Company's portion of jointly-owned *Utility Plant*, along with that plant's related operating expenses, is presented in these financial statements in proportion to the ownership percentage.

Nonutility Plant & Related Depreciation

The depreciation of *Nonutility Plant* is charged against income over its estimated useful life, using the straight-line method of depreciation. When nonutility property is retired, or otherwise disposed of, the asset and accumulated depreciation are removed, and the resulting gain or loss is reflected in income, typically impacting operating expenses.

Impairment Reviews

Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate the carrying amount may be impaired. This impairment review involves the comparison of an asset's (or group of assets') carrying value to the estimated future cash flows the asset (or asset group) is expected to generate over a remaining life. If this evaluation were to conclude the carrying value is impaired, an impairment charge would be recorded based on the difference between the carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations.

Goodwill

Goodwill recorded on the *Balance Sheets* results from business acquisitions and is based on a fair value allocation of the businesses' purchase price at the time of acquisition. Goodwill is charged to expense only when it is impaired. The Company tests its goodwill for impairment at a reporting unit level. These tests are performed at least annually and at the beginning of each year. Impairment reviews consist of a comparison of fair value to the carrying amount. If the fair value is less than the carrying amount, an impairment loss is recognized in operations. No goodwill impairments have been recorded during the periods presented.

Regulation

Retail public utility operations are subject to regulation by the IURC. The Company's accounting policies give recognition to the ratemaking and accounting practices authorized by this agency.

Refundable or Recoverable Gas Costs & Cost of Fuel & Purchased Power

All metered gas rates contain a gas cost adjustment clause (GCA) that allows the Company to charge for changes in the cost of purchased gas. Metered electric rates contain a fuel adjustment clause (FAC) that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to a variable benchmark based on NYMEX natural gas prices, is also recovered through regulatory proceedings. The Company records any under or over-recovery resulting from the GCA and FAC each month in revenues. A corresponding asset or liability is recorded until the under or over- recovery is billed or refunded to utility customers. The cost of gas sold is charged to operating expense as delivered to customers, and the cost of fuel and purchased power for electric generation is charged to operating expense when consumed.

Regulatory Assets & Liabilities

Regulatory assets represent certain incurred costs, which will result in probable future cash recoveries from customers through the ratemaking process. *Regulatory liabilities* represent probable expenditures by the Company for removal costs or future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. The Company continually assesses the recoverability of costs recognized as regulatory assets and liabilities and the ability to recognize new regulatory assets and liabilities associated with its regulated utility operations. Given the current regulatory environment in its jurisdiction, the Company believes such accounting is appropriate.

The Company collects an estimated cost of removal of its utility plant through depreciation rates established in regulatory proceedings. The Company records amounts expensed in advance of payments as a *Regulatory liability* because the liability does not meet the threshold of an asset retirement obligation.

Asset Retirement Obligations

A portion of removal costs related to interim retirements of gas utility pipeline and utility poles, certain asbestos-related issues, and reclamation activities meet the definition of an asset retirement obligation (ARO). The Company records the fair value of a liability for a legal ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. The liability is accreted, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company settles the obligation for its recorded amount or incurs a gain or loss. To the extent regulation is involved, regulatory assets and liabilities result when accretion and amortization is adjusted to match rates established by regulators and any gain or loss is subject to deferral.

Energy Contracts & Derivatives

The Company will periodically execute derivative contracts in the normal course of operations while buying and selling commodities to be used in operations, optimizing its generation assets, and managing risk. A derivative is recognized on the balance sheet as an asset or liability measured at its fair market value and the change in the derivative's fair market value depends on the intended use of the derivative and resulting designation.

When an energy contract that is a derivative is designated and documented as a normal purchase or normal sale (NPNS), it is exempt from mark-to-market accounting. Such energy contracts include Real Time and Day Ahead purchase and sale contracts with the MISO, certain natural gas purchases, and wind farm and other electric generating contracts.

When the Company engages in energy contracts and financial contracts that are derivatives and are not subject to the NPNS or other exclusions, such contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and when the contracts are expected to be settled. Contracts and any associated collateral with counter-parties subject to master netting arrangements are presented net in the *Balance Sheets*. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to regulatory accounting treatment. The offset to contracts affected by regulatory accounting treatment, which includes most of the Company's executed energy and financial contracts, are marked to market as a regulatory asset or liability. Market value for derivative contracts is determined using quoted market prices from independent sources or from internal models. As of and for the periods presented, derivative activity is not material to these financial statements.

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, typically at a point in time,resulting in revenue being recognized at a single point in time based upon the delivery of services to customers.

MISO Transactions

With the IURC's approval, the Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electrical transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities as well as other utilities in the region. The Company is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded in *Cost of fuel & purchased power* and net sales in a single hour are recorded in *Electric utility revenues*. On occasion, prior period transactions are resettled outside the routine process due to a change in the MISO's tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

The Company also receives transmission revenue that results from other members' use of the Company's transmission system. These revenues are also included in *Electric utility revenues.* Generally, these transmission revenues along with costs charged by the MISO are considered components of base rates and any variance from that included in base rates is recovered from / refunded to retail customers through tracking mechanisms.

Utility Receipts Taxes

A portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $8.8 million in 2018 and $8.6 million in 2017. Expense associated with utility receipts taxes are recorded as a component of *Taxes other than income taxes*.

Fair Value Measurements

Certain assets and liabilities are valued and disclosed at fair value. Nonfinancial assets and liabilities include the initial measurement of an asset retirement obligation or the use of fair value in goodwill, intangible assets, and long-lived assets impairment tests. FASB guidance provides the framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are described as follows:

Level 1 Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets that the Company has the ability to access.

Level 2 Inputs to the valuation methodology include

- quoted prices for similar assets or liabilities in active markets;
- quoted prices for identical or similar assets or liabilities in inactive markets;
- inputs other than quoted prices that are observable for the asset or liability;
- inputs that are derived principally from or corroborated by observable market data by correlation or other means

If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.

Level 3 Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used maximize the use of observable inputs and minimize the use of unobservable inputs.

Other Significant Policies

Included elsewhere in these notes are significant accounting policies related to retirement plans and other postretirement benefits, intercompany allocations and income taxes (Note 6).

3. Revenue

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

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

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

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 include: Gas Utility Services and Electric Utility Services.

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

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

(In millions)	Year Ended December 31, 2018
Gas Utility Services	
Residential	$ 65,125
Commercial	24,055
Industrial	10,576
Other	288
Total Gas Utility Services	$ 100,044
Electric Utility Services	
Residential	$ 210,232
Commercial	149,255
Industrial	162,143
Other	60,874
Total Electric Utility Services	$ 582,504

Contract Balances

The Company does not have any material contract balances (right to consideration for services already provided or obligations to provide services in the future for consideration already received) as of January 1, 2018 or December 31, 2018. Substantially all the Company's accounts receivable results from contracts with customers.

Remaining Performance Obligations

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

4. Utility Plant & Deprecation

The original cost of *Utility plant*, together with depreciation rates expressed as a percentage of original cost, follows:

(In thousands)	At and For the Year Ended December 31, 2018 Original Cost	2018 Depreciation Rates as a Percent of Original Cost	2017 Original Cost	2017 Depreciation Rates as a Percent of Original Cost
Electric utility plant	$2,945,765	3.3%	$2,833,503	3.3%
Gas utility plant	482,211	2.8%	426,934	2.8%
Common utility plant	67,590	3.2%	59,059	3.2%
Construction work in progress	71,499	—	47,556	—
Asset retirement obligations	51,267	—	50,402	—
Total original cost	**$3,618,332**		**$3,417,454**	

The Company and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own a 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common. The Company's share of the cost of this unit at December 31, 2018, is $192.1 million with accumulated depreciation totaling $128.5 million. AGC and the Company share equally in the cost of operation and output of the unit. The Company's share of operating costs is included in *Other operating expenses* in the *Statements of Income.*

5. Regulatory Assets & Liabilities

Regulatory Assets

Regulatory assets consist of the following:

(In thousands)	At December 31, 2018	2017
Future amounts recoverable from ratepayers related to:		
Asset retirement obligations & other	$ 24,014	$20,601
Net deferred income taxes	2,955	2,517
	26,969	23,118
Amounts deferred for future recovery related to:		
Cost recovery riders & other	47,366	32,429
	47,366	32,429
Amounts currently recovered through customer rates related to:		
Authorized trackers	19,478	20,277
Deferred coal costs	7,068	14,136
Unamortized debt issue costs, reacquisition premiums & hedging proceeds	4,941	5,343
	31,487	39,756
Total regulatory assets	**$105,822**	**$95,303**

Of the $31.5 million currently being recovered in rates charged to customers, no amounts are earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $4.9 million, is 21 years. The remainder of the regulatory assets are being recovered timely through periodic recovery mechanisms. The Company has rate orders for all deferred costs not yet in rates and therefore believes future recovery is probable.

Regulatory assets for asset retirement obligations are a result of costs incurred for expected retirement activity for the Company's ash ponds beyond what has been recovered in rates. The Company believes the recovery of these assets are probable as the costs are currently being recovered in rates.

Regulatory Liabilities

At December 31, 2018 and 2017, the Company had regulatory liabilities of approximately $256.0 million and $265.2 million, respectively, of which $54.3 million and $55.4 million related to cost of removal obligations and $201.4 million and $209.4 million related to deferred taxes, at December 31, 2018 and 2017, respectively. The deferred tax related regulatory liability is primarily the revaluation of deferred taxes at the reduced federal corporate tax rate that was enacted on December 22, 2017. These regulatory liabilities are being refunded to customers over time as ordered by the IURC.

6. Transactions with Other Vectren Companies & Affiliates

Vectren Infrastructure Services Corporation (VISCO)

VISCO, a wholly owned subsidiary of Vectren, provides underground pipeline construction and repair services. VISCO's customers include the Company and fees incurred by the Company totaled $16.0 million in 2018 and $22.3 million in 2017. Amounts owed to VISCO at December 31, 2018 and 2017 are included in *Payables to other Vectren companies.*

Support Services and Purchases

Vectren and the Company's parent provide corporate and general and administrative services to the Company and allocate certain costs to the Company. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. The Company received corporate allocations totaling $52.9 million and $56.9 million for the years ended December 31, 2018, and 2017, respectively. Amounts owed to Vectren and the Company's parent at December 31, 2018 and 2017 are included in *Payables to other Vectren companies.*

Retirement Plans & Other Postretirement Benefits

At December 31, 2018, Vectren maintains three qualified defined benefit pension plans (Vectren Corporation Non-Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The pension and SERP plans are closed to new participants. The defined benefit pension plans and postretirement benefit plan, which cover the Company's eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. Current and former employees of Vectren and its subsidiaries, which include the Company, comprise the participants and retirees covered by these plans.

Vectren satisfies the future funding requirements for funded plans and the payment of benefits for unfunded plans from general corporate assets and, as necessary, relies on the Company to support the funding of these obligations. However, the Company has no contractual funding obligation to the plans. Contributions of $1.5 million were made to Vectren for funded plans in 2018 and no contributions were made to Vectren in 2017. The combined funded status of Vectren's funded plans was approximately 89 percent and 92 percent at December 31, 2018 and 2017, respectively.

Vectren allocates retirement plan and other postretirement benefit plan periodic cost calculated pursuant to US GAAP to its subsidiaries, which is also how the Company recovers retirement plan periodic costs through base rates. Periodic cost is charged to the Company following a labor cost allocation methodology and results in retirement costs being allocated to both operating expense and capital projects. Costs totaling $3.7 million were charged to the Company in both years ended December 31, 2018 and 2017.

Any difference between the Company's funding requirements to Vectren and allocated periodic costs is recognized by the Company as an intercompany asset or liability. The allocation methodology to determine the intercompany funding requirements from the subsidiaries to Vectren is consistent with FASB guidance related to "multiemployer" benefit accounting. Neither plan assets nor plan obligations as calculated pursuant to GAAP by Vectren are allocated to individual subsidiaries.

As of December 31, 2018 and 2017, the Company had $25.6 million and $27.3 million, respectively, included in *Other Assets* representing defined benefit pension funding by the Company to Vectren that is yet to be reflected in costs. As of December 31, 2018 and 2017, the Company had $19.0 million and $20.9 million, respectively, included in *Deferred credits & other liabilities* representing costs related to other postretirement benefits charged to the Company that is yet to be funded to Vectren. The Company's labor allocation methodology is used to compute the Company's funding of the defined benefit retirement and other postretirement plans to Vectren, which is consistent with the regulatory ratemaking processes of the Company.

Share-Based Incentive Plans and Deferred Compensation Plans

The Company does not have share-based compensation plans separate from Vectren. The Company recognizes its allocated portion of expenses related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash, that liability is pushed down to SIGECO. As of December 31, 2018 and 2017, $29.4 million and $26.7 million, respectively, is included in *Accrued liabilities* and *Deferred credits & other liabilities* and represents obligations that are yet to be funded to Vectren. Subsequent to the February 1, 2019 completion of the Merger, and pursuant to the Merger Agreement, all Vectren's share-based awards have been settled and a majority of its deferred compensation liabilities have been settled.

Cash Management Arrangements

The Company participates in the centralized cash management program of the Company's parent. See Note 7 regarding long-term and short-term intercompany borrowing arrangements.

Guarantees of the Company's Parent Debt

The three operating utility companies of the Company's parent, SIGECO, Indiana Gas Company, Inc. (Indiana Gas) and Vectren Energy Delivery of Ohio, Inc. (VEDO) are guarantors of its $400 million short-term credit facility, of which approximately $167 million is outstanding at December 31, 2018, and its $1.4 billion in unsecured senior notes and term loans outstanding at December 31, 2018. The majority of the unsecured senior notes and term loans outstanding of the Company's parent are allocated to the operating utility companies. The guarantees are full and unconditional and joint and several, and the Company's parent has no subsidiaries other than the subsidiary guarantors.

The Merger constituted a "Change of Control" under the senior notes. At December 31, 2018, the prepayment offer was accepted on $568 million of the the senior notes. At merger close, CenterPoint loaned the Company's parent the proceeds necessary to make the prepayment at the same interest rate and term as the notes being prepaid. The CenterPoint notes are not guaranteed by the Company or the other operating utility companies of the Company's parent.

Income Taxes

The Company does not file federal or state income tax returns separate from those filed by Vectren. Vectren files a consolidated U.S. federal income tax return, and Vectren and/or certain of its subsidiaries file income tax returns in various states. Pursuant to a tax sharing agreement and for financial reporting purposes, Vectren subsidiaries record income taxes on a separate company basis. The Company's allocated share of tax effects resulting from it being a part of Vectren's consolidated tax group are recorded at the Company's parent level. Current taxes payable/receivable are settled with Vectren in cash quarterly and after filing the consolidated federal and state income tax returns.

Deferred income taxes are provided for temporary differences between the tax basis (adjusted for related unrecognized tax benefits, if any) of an asset or liability and its reported amount in the financial statements. Deferred tax assets and liabilities are computed based on the currently-enacted statutory income tax rates that are expected to be applicable when the temporary differences are scheduled to reverse. The Company recognizes regulatory liabilities for deferred taxes provided in excess of the current statutory tax rate and regulatory assets for deferred taxes provided at rates less than the current statutory tax rate. Such tax-related regulatory assets and liabilities are reported at the revenue requirement level and amortized to income as the related temporary differences reverse, generally over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that the deferred tax assets will be realized.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more- likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company reports interest and penalties associated with unrecognized tax benefits within *Income taxes* in the *Statements of Income* and reports tax liabilities related to unrecognized tax benefits as part of *Deferred credits & other liabilities*.

Investment tax credits (ITCs) are deferred and amortized to income over the approximate lives of the related property. Production tax credits (PTCs) are recognized as energy is generated and sold based on a per kilowatt hour rate prescribed in applicable federal and state statutes.

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 are 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 under Section 118 of the IRC regarding taxability of contributions made by government or civic groups.

The reduction in the federal corporate rate resulted in $150.2 million in excess federal deferred income taxes, which resulted in a regulatory liability of $209.4 million after gross-up.

The Company's gas and electric utilities currently recover corporate income tax expense in approved rates charged to customers. The IURC issued an order which initiated a proceeding to investigate the impact of the TCJA on utility companies and customers within the state. In addition, the IURC ordered the Company to establish regulatory liabilities to record all estimated impacts of tax reform starting January 1, 2018. As of December 31, 2018, the Company has established $9.9M in *Accrued Liabilities* associated with the other impacts of tax reform.

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. The refund of excess deferred taxes and regulatory liabilities commenced in November 2018 for the Company's electric customers and in January 2019 for the Company's gas customers.

The components of income tax expense and amortization of investment tax credits follow:

	Year Ended December 31,	
(In thousands)	2018	2017
Current:		
Federal	$ 28,189	$ 27,462
State	4,899	6,407
Total current tax expense	**33,088**	**33,869**
Deferred:		
Federal	(15,408)	10,179
State	1,392	467
Total deferred tax expense	**(14,016)**	**10,646**
Amortization of investment tax credit deferred / (amortized)	3,382	(405)
Total income tax expense	**$ 22,454**	**$ 44,110**

A reconciliation of the federal statutory rate to the effective income tax rate follows:

	Year Ended December 31, 2018	2017
Statutory rate	21.0%	35.0%
Federal tax law change impacts	(4.1)	—
State & local taxes, net of federal benefit	5.0	4.2
All other - net	(0.3)	(3.6)
Effective tax rate	**21.6%**	**35.6%**

Significant components of the net deferred tax liability follow:

(In thousands)	At December 31, 2018	2017
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$232,129	$233,435
Regulatory assets recoverable through future rates	4,937	4,635
Employee benefit obligations	(2,827)	(618)
Regulatory liabilities to be settled through future rates	(51,665)	(53,284)
Deferred fuel costs	5,768	9,570
Other – net	1,735	1,514
Net deferred tax liability	**$190,077**	**$195,252**

At December 31, 2018 and 2017, investment tax credits totaling $4.5 million and $1.1 million, respectively, are included in *Deferred credits & other liabilities.*

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The net liability on the *Balance Sheet* for unrecognized tax benefits inclusive of interest and penalties totaled $0.3 million and $0.2 million at December 31, 2018 and 2017, respectively.

Vectren and/or certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) is currently examining Vectren's U.S. federal income tax return for tax year December 31, 2016. The State of Indiana, Vectren's primary state tax jurisdiction, is currently examining Vectren's consolidated state returns for December 31, 2015 through 2017 and has previously concluded examinations of state income tax returns for tax years through December 31, 2011. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2015 except to the extent of refunds claimed on amended tax returns. The statutes of limitations for assessment of the 2013 tax year related to the amended federal tax return will expire in 2020. The statutes of limitations for assessment of the 2012 through 2014 tax years related to the amended Indiana income tax returns will expire in 2019 through 2020.

7. Borrowing Arrangements & Other Financing Transactions

Short-Term Borrowings

The Company relies on the short-term borrowing arrangements of the Company's parent for its short-term working capital needs. There were no borrowings outstanding at December 31, 2018 and $1.7 million outstanding at December 31, 2017. The intercompany credit line totals $400 million, but is limited to the available capacity of the Company's parent ($233 million at December 31, 2018) and is subject to the same terms and conditions as its short term borrowing arrangements, including its commercial paper program. Short-term borrowings bear interest at the Company's parent weighted average daily cost of short-term funds.

See the table below for interest rates and outstanding balances:

(In thousands)	Intercompany Borrowings 2018	2017
Year End		
Balance Outstanding	$ —	$ 1,718
Weighted Average Interest Rate	2.96%	1.91%
Annual Average		
Balance Outstanding	$ 6,445	$ 249
Weighted Average Interest Rate	2.34%	1.47%
Maximum Month End Balance Outstanding	$ 25,542	$ 1,718

Long-Term Debt

Long-term senior unsecured obligations and first mortgage bonds outstanding follow:

(In thousands)	At December 31, 2018	2017
Fixed Rate Senior Unsecured Notes Payable to Utility Holdings:		
2018, 5.75%	$ —	$ 61,880
2020, 6.28%	99,461	74,596
2021, 4.67%	54,612	54,612
2023, 3.72%	24,847	24,847
2028, 3.20%	26,856	26,856
2032, 3.26%	74,587	—
2035, 6.10%	25,284	25,284
2035, 3.90%	16,580	16,580
2043, 4.25%	47,745	47,745
2045, 4.36%	16,580	16,580
2047, 3.93%	29,832	29,832
2055, 4.51%	16,580	16,580
Variable Rate Term Loans		
2020, current adjustable rate, 3.20%	14,995	—
Total long-term debt payable to Utility Holdings	**447,959**	**395,392**
Current maturities	—	(61,880)
Total long-term debt payable to Utility Holdings	**$447,959**	**$333,512**
First Mortgage Bonds Payable to Third Parties:		
2022, 2013 Series C, current adjustable rate 2.75%, tax exempt	$ 4,640	$ 4,640
2024, 2013 Series D, current adjustable rate 2.75%, tax exempt	22,500	22,500
2025, 2014 Series B, current adjustable rate 2.75%, tax exempt	41,275	41,275
2029, 1999 Series, 6.72%	80,000	80,000
2037, 2013 Series E, current adjustable rate 2.75%, tax exempt	22,000	22,000
2038, 2013 Series A, current adjustable rate 2.75%, tax exempt	22,200	22,200
2043, 2013 Series B, current adjustable rate, 2.75%, tax exempt	39,550	39,550
2044, 2014 Series A, 4.00%, tax exempt	22,300	22,300
2055, 2015 Series Mt. Vernon, 2.375%, tax exempt	23,000	23,000
2055, 2015 Series Warrick County, 2.375%, tax exempt	15,200	15,200
Total first mortgage bonds payable to third parties	**292,665**	**292,665**
Debt issuance cost	(3,909)	(3,675)
Unamortized debt premium, discount & other - net	(411)	(473)
Total long-term debt payable to third parties - net	**$288,345**	**$288,517**

Term Loan

On July 30, 2018, the Company's parent closed a two-year term loan with two banking partners. The term loan agreement provided for a $250 million draw at closing and the remaining $50 million was drawn on December 14, 2018. Proceeds from the term loan were 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 ranging from 70 to 90 basis points depending on the Company's parent credit rating. The current spread is 70 basis points and such spread remain unchanged by recent actions taken by rating agencies. In addition, the term loan contains a provision that should the Company's parent 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 the Company's parent wholly-owned operating companies, SIGECO, Indiana Gas, and VEDO. The Company received approximately $15 million of these proceeds.

SIGECO Variable Rate Tax-Exempt Bonds

On March 1, 2018 and May 1, 2018, the Company executed first and second amendments to a Bond Purchase and Covenants Agreement originally signed in September 2017. These amendments provided the Company 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 a final maturity date of January 1, 2022;
- 2013 Series D Notes with a principal of $22.5 million and a final maturity date of March 1, 2024;
- 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 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 the Company's credit rating, among others, may result in an actual interest rate above or below the anticipated fixed rate. Regulatory orders require the Company 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.

Mandatory Tenders

At December 31, 2018, certain series of SIGECO bonds, aggregating $185.7 million are subject to mandatory tenders prior to the bonds' final maturities. $38.2 million will be tendered in 2020 and $147.5 million will be tendered in 2023.

Call Options

At December 31, 2018, certain series of SIGECO bonds may be called at SIGECO's option. $22.3 million is callable in 2019.

Future Long-Term Debt Sinking Fund Requirements and Maturities

The annual sinking fund requirement of the Company's first mortgage bonds is 1 percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. The Company met the 2018 sinking fund requirement by this means and expects to also meet this requirement in 2019 in this manner. Accordingly, the sinking fund requirement is excluded from *Current liabilities* in the *Balance Sheets*. At December 31, 2018, $1.6 billion of utility plant remained unfunded under the Company's Mortgage Indenture. The Company's gross utility plant balance subject to the Mortgage Indenture approximated $3.6 billion at December 31, 2018.

Maturities of long-term debt during the five years following 2018 (in millions) are $114.5 in 2020, $54.6 in 2021, $4.6 in 2022, $24.8 in 2023 and $542.1 thereafter. There are no maturities of long-term debt in 2019.

Covenants

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. As of December 31, 2018, the Company was in compliance with all financial debt covenants.

8. Commitments & Contingencies

Purchase Commitments

The Company has firm commitments to purchase natural gas for up to a five year term, with the majority of these commitments being a term of two years or less. The Company also has other firm and non-firm commitments to purchase coal, electricity, as well as certain transportation and storage rights, some of which are firm commitments under five and twenty year arrangements. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Letters of Credit

The Company, from time to time, issues letters of credit to support operations. At December 31, 2018, letters of credit outstanding total $8.6 million.

Legal and Regulatory Proceedings

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

9. Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560

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

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 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.

On December 5, 2018, the IURC issued an order (December 2018 order) for the third semi-annual filing approving the inclusion in rates of investments made from November 2017 through April 2018. Through the December 2018 order, approximately $59 million of the approved capital investment plan has been incurred and approved for recovery.

As of December 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $2.2 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.

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 and the remaining investment went into service in 2016. At December 31, 2018 and December 31, 2017, respectively, the Company has regulatory assets totaling $18.6 million and $12.8 million related to depreciation and operating expenses and $6.5 million and $4.7 million 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. On March 17, 2019, the Indiana Court of Appeals issued an order upholding the Commission's Order of the 2016-2017 Energy Efficiency Plan in its entirety.

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. On February 19, 2019, the Indiana Court of Appeals issued an order upholding the Commission's Order of the 2018-2020 Energy Efficiency Plan in its entirety.

For the twelve months ended December 31, 2018 and 2017 the Company recognized electric utility revenue of $12.3 million and $11.6 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 an order authorizing a 10.32 percent base ROE for the first refund period and prospectively from the date of the order. Pursuant to a US Court of Appeals decision in April 2017 which challenged FERC's prior methodology for calculating ROE, in October 2018, the FERC issued an order which established a modified calculation ROE framework. On November 15, 2018, the FERC issued an order reopening the first complaint case taking the modified ROE framework into consideration. The order proposed a preliminary ROE not materially different from the original order and directed participants to submit briefs regarding the proposed approach. Reply comments in response to the order were due in February 2019.

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. Following the resolution of the first complaint case, a base ROE will be established for this period and prospectively from the date of the order.

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, continues to evaluate the potential impacts of the outstanding cases, and does not expect any impact to be material. As of December 31, 2018, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $130.1 million at December 31, 2018.

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 1, 2019, the Company filed its first request for recovery of these investments using the mechanism allowed under Senate Bill 29, with costs of the completed projects totaling approximately $13 million as of December 31, 2018.

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. On March 20, 2019, the IURC approved the settlement agreement in its entirety and granted the Company a CPCN to construct the 50MW universal solar array.

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.

10. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

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

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

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, 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.

Requests for Recovery under 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 nine semi-annual orders which approved the inclusion in rates of approximately $150 million of approved capital investments through June 30, 2018, and approved updates to the seven-year capital investment plan reflecting capital expenditures of approximately $238 million.

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 has removed the associated projects that were not previously the subject of final orders, totaling approximately $5 million over the remaining term of the plan. Such projects are still eligible for recovery in a future base rate case. The Company removed the projects from the plan in accordance with the Opinion when it filed supplemental testimony in its eighth semi-annual TDSIC proceeding on July 25, 2018. The Company does not expect a resulting material impact to results of operations or cash flow from operations.

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. The Company received the IURC Order approving the request for recovery and inclusion in the approved seven-year capital investment plan on December 28, 2017. Approximately $8 million of operating expenses and $5 million of capital investments have been included in the plan over a four- year period beginning in 2017.

At December 31, 2018 and December 31, 2017, the Company has regulatory assets related to the Plan totaling $23.4 million and $16.4 million, respectively.

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.

11. Environmental and Sustainability Matters

The Company initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report of Vectren. 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 Vectren's Corporate Responsibility and Sustainability Committee, as well as vetted with Vectren's Board of Directors. Further discussion of key goals, strategies, and governance practices can be found in Vectren'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 the Company's electric operations.

<u>Coal Ash Waste Disposal, Ash Ponds and Water</u>

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. 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, Vectren 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 December 31, 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.

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. In the case of Vectren's water discharge permits, in 2017 the Indiana Department of Environmental Management (IDEM) issued final renewals for Company's F.B. Culley and A.B. Brown power plants. IDEM agreed that units identified for retirement by December 2023 would not be required to install new treatment technology to meet ELG, and approved a 2020 compliance date for dry bottom ash and a 2023 compliance date for flue gas desulfurization wastewater treatment standards for the remaining coal-fired unit at F.B. Culley.

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

MATS Reconsideration

On December 27, 2018, US EPA proposed to revise the Supplemental Cost Finding for the Mercury and Air Toxics Standards (MATS) rule, as well as the hazardous air pollutants risk and technology review (RTR) required under the CAA. Specifically, the agency proposes to determine that it is not "appropriate and necessary" to regulate hazardous air pollutant emission from power plants under Section 112 of the CAA. Under the proposal, the emission standards and other requirements of the MATS rule, first promulgated in 2012, would remain in place, since EPA is not proposing to remove coal-fired power plants from the list of sources that are regulated under Section 112 of the Act. The Company is in full compliance with MATS and does not anticipate significant impacts or operational changes under this proposal.

Climate Change and Carbon Strategy

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 CO2 by an average of 35 percent (on a tonnage basis), and will increase that total to 60 percent at the conclusion of its generation transition plan, well above the 32 percent reduction that would be required under the CPP. While the litigation and the EPA's reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

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

The Company has identified its involvement in five manufactured gas plant sites, all of which are currently enrolled in the IDEM's Voluntary Remediation Program (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 $20.8 million. 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, the Company has settlement agreements with all known insurance carriers and has received substantially all 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 has recorded all costs which it presently expects 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 December 31, 2018 and December 31, 2017, approximately $1.4 million and $1.1 million, respectively of accrued, but not yet spent, costs are included in *Other Liabilities* related to these sites.

12. Fair Value Measurements

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

	At December 31,			
	2018		2017	
(In thousands)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt payable to third parties	$288,345	$ 301,509	$288,517	$ 307,685
Long-term debt payable to Utility Holdings	447,959	455,586	395,392	418,102
Short-term borrowings payable to Utility Holdings	—	—	1,718	1,718
Short-term notes receivable from Utility Holdings	98,678	98,678	—	—
Natural gas purchase instrument liabilities (1)	1,749	1,749	354	354
Interest rate swap liabilities (2)	94	94	1,368	1,368
Cash & cash equivalents	2,284	2,284	2,275	2,275

(1) Presented in "Accrued liabilities" and "Deferred credits & other liabilities" on the Balance Sheets.
(2) Presented in "Deferred credits & other liabilities" on the Balance Sheets.

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 entered into two five-year forward purchase arrangements to hedge the variable 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 gas cost recovery mechanism.

The Company executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the 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.

13. Additional Balance Sheet & Operational Information

Inventories in the *Balance Sheets* consist of the following:

(In thousands)	At December 31, 2018	2017
Materials & supplies	$33,489	$32,681
Fuel (coal and oil) for electric generation	16,650	43,086
Gas in storage – at LIFO cost	19,726	17,505
Other	12	—
Total inventories	**$69,877**	**$93,272**

Based on the average cost of gas purchased during December 2018 and 2017, the cost of replacing gas in storage carried at LIFO cost is less than the carrying value at December 31, 2018 and 2017 by approximately $3 million and $4 million, respectively. All other inventories are carried at average cost. The Company sources most of its coal supply from a single third party and also purchases most of its natural gas from a different single third party. Rates charged to natural gas customers contain a gas cost adjustment clause and electric rates contain a fuel adjustment clause that allow for the timely adjustment in charges to reflect changes in the cost of gas and cost for fuel.

Prepayments & other current assets in the *Balance Sheets* consist of the following:

(In thousands)	At December 31, 2018	2017
Prepaid taxes	$4,268	$ 375
Other	2,135	1,299
Total prepayments & other current assets	**$6,403**	**$1,674**

Accrued liabilities in the *Balance Sheets* consist of the following:

(In thousands)	At December 31, 2018	2017
Accrued taxes	$11,286	$18,600
Refunds to customers & customer deposits	26,410	16,379
Accrued interest	5,103	5,253
Tax collections payable	2,876	2,859
Accrued salaries & other	10,846	7,784
Total accrued liabilities	**$56,521**	**$50,875**

Asset retirement obligations included in *Deferred Credits and Other Liabilities* in the *Balance Sheets* roll forward as follows:

(In thousands)	2018	2017
Asset retirement obligation, January 1	$61,142	$61,796
Accretion	2,272	2,077
Changes in estimates, net of cash payments	865	(2,731)
Asset retirement obligation, December 31	**$64,279**	**$61,142**

Other income – net in the *Statements of Income* consists of the following:

(In thousands)	Year ended December 31, 2018	2017
AFUDC – borrowed funds	$ 5,256	$ 3,758
AFUDC – equity funds	2,553	2,030
Other	81	(249)
Total other income - net	**$ 7,890**	**$ 5,539**

Supplemental Cash Flow Information:

(In thousands)	Year ended December 31, 2018	2017
Cash paid for:		
Income taxes	$ 44,147	$ 22,206
Interest	33,085	31,496

As of December 31, 2018 and 2017, the Company has accruals related to utility plant purchases totaling approximately $13.1 million and $9.2 million, respectively.

14. Impact of Recently Issued Accounting Standards

Leases

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

ASU 2016-02 includes multiple practical expedients that may be elected but must be elected as a package. These practical expedients allow lessees and lessors to: 1) not reassess expired or existing contracts to determine whether they are subject to lease accounting guidance, (2) not reconsider lease classification at transition, and (3) not evaluate previously capitalized initial direct costs under the revised requirements. The Company has elected to utilize this package of three expedients.

The Company has adopted an accounting policy that exempts leases with terms of less than one year from the recognition requirements of the standard. The ASU also provides lessees the option of electing an accounting policy, by class of underlying asset, in which the lessee may choose not to separate nonlease components from lease components. The Company has adopted this practical expedient for certain classes of leases.

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 has applied 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 has applied the election under 2018-11 to its 2016-02 adoption.

As of December 31, 2018, the Company has reviewed substantially all its leases and related contracts and has completed its preliminary evaluation of the guidance. The population primarily consists of business and office facility leases. While the Company is continuing to evaluate the full impact of the standard on the consolidated financial statements and related disclosures, upon adoption, the Company will recognize right-of-use assets and lease liabilities for leases currently classified as operating leases. 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.