Section 1: 8-K (8-K - SIG 2017 REPORTING PACKAGE (SHELL))

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 29, 2018**

VECTREN CORPORATION

(Exact name of registrant as specified in its charter)

Commission File No.	Registrant, State of Incorporation, Address, and Telephone Number	I.R.S Employer Identification No.
1-15467	Vectren Corporation (An Indiana Corporation) One Vectren Square, Evansville, Indiana 47708 (812) 491-4000	35-2086905
1-16739	Vectren Utility Holdings, Inc. (An Indiana Corporation) One Vectren Square, Evansville, Indiana 47708 (812) 491-4000	35-2104850

Former name or address, if changed since last report:

N/A

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:

☐ Written communications pursuant to Rule 425 under the Securities Act (17CFR 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 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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 Southern Indiana Gas & Electric Company (SIGECO), a wholly-owned subsidiary of Vectren Utility Holdings, Inc. (Utility Holdings). Utility Holdings is a wholly-owned subsidiary of Vectren Corporation (the Company).

Exhibit 99.1 to this Current Report on Form 8-K includes audited financial statements for the years ended December 31, 2017 and 2016, an abbreviated analysis of results of operations, and operating statistics. These financial statements are not intended to comply with Regulation S-X or Regulation S-K as SIGECO is not a registrant.

In accordance with SEC Release No. 33-8176, the information contained in the audited financial statements shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

In connection with the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, the Company is hereby furnishing cautionary statements identifying important factors that could cause actual results of the Company and its subsidiaries, including Vectren Utility Holdings, Inc and Southern Indiana Gas and Electric Company, to differ materially from those projected in forward-looking statements of the Company and its subsidiaries made by, or on behalf of, the Company and its subsidiaries. These cautionary statements are attached as Exhibit 99.2.

Item 9.01 Exhibits

Exhibit Number	Description
99.1	Reporting Package of Southern Indiana Gas & Electric Company
99.2	Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

SIGNATURES

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

VECTREN CORPORATION
VECTREN UTILITY HOLDINGS, INC.

March 29, 2018

By: /s/ M. Susan Hardwick
M. Susan Hardwick
Executive Vice President and Chief Financial Officer

INDEX TO EXHIBITS

The following Exhibits are filed as part of this Report to the extent described in Item 7.01:

Exhibit Number	Description
99.1	Reporting Package of Southern Indiana Gas & Electric Company
99.2	Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

(Back To Top)

Section 2: EX-99.1 (EXHIBIT 99.1 - SIG 2017 REPORTING PACKAGE)

SOUTHERN INDIANA GAS & ELECTRIC COMPANY REPORTING PACKAGE

For the year ended December 31, 2017

Contents

Additional Information

This annual reporting package provides additional information regarding the operations of Southern Indiana Gas and Electric Company (the Company, or SIGECO). This information is supplemental to Vectren Corporation’s (Vectren) annual report for the year ended December 31, 2017, filed on Form 10-K with the Securities and Exchange Commission on February 21, 2018 and Vectren Utility Holdings, Inc.’s (Utility Holdings or the Company's parent) 10-K filed on March 8, 2018. Vectren and the Company's parent make available their Securities and Exchange Commission filings and recent annual reports free of charge through its website at www.vectren.com.

Frequently Used Terms

Administration: President Trump's Administration
AFUDC: allowance for funds used during construction
ASC: Accounting Standards Codification
ASU: Accounting Standards Update
DOT: Department of Transportation
EPA: Environmental Protection Agency
FAC: Fuel Adjustment Clause
FASB: Financial Accounting Standards Board
FERC: Federal Energy Regulatory Commission
GAAP: Generally Accepted Accounting Principles
GCA: Gas Cost Adjustment
IDEM: Indiana Department of Environmental Management
IRP: Integrated Resource Plan
IURC: Indiana Utility Regulatory Commission
kV: Kilovolt
MCF / MMCF / BCF: thousands / millions / billions of cubic feet
MDth / MMDth: thousands / millions of dekatherms
MISO: Midcontinent Independent System Operator
MMBTU: millions of British thermal units
MW: megawatts
MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
NOx: nitrogen oxide
OUCC: Indiana Office of the Utility Consumer Counselor
PHMSA: Pipeline Hazardous Materials Safety Administration
TCJA: Tax Cuts and Jobs Act
Throughput: combined gas sales and gas transportation volumes

INDEPENDENT AUDITORS’ REPORT

To the Shareholder and Board of Directors of Southern Indiana Gas & Electric Company:

We have audited the accompanying financial statements of Southern Indiana Gas & Electric Company (the "Company"), which comprise the balance sheets as of December 31, 2017 and 2016, and the related statements of income, cash flow, 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 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 financial statements referred to above present fairly, in all material respects, the financial position of Southern Indiana Gas & Electric Company as of December 31, 2017 and 2016, 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 29, 2018

FINANCIAL STATEMENTS

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

	December 31,	
	2017	2016
ASSETS		
Utility Plant		
Original cost	$ 3,417,454	$ 3,279,323
Less: accumulated depreciation & amortization	1,527,646	1,428,750
Net utility plant	**1,889,808**	**1,850,573**
Current Assets		
Cash & cash equivalents	2,275	1,499
Notes receivable from Utility Holdings	—	17,496
Accounts receivable - less reserves of $1,967 & $1,706, respectively	45,641	50,471
Receivables from other Vectren companies	3	17
Accrued unbilled revenues	38,744	32,976
Inventories	93,272	92,315
Recoverable fuel & natural gas costs	9,797	7,006
Prepayments & other current assets	1,674	5,920
Total current assets	**191,406**	**207,700**
Investments in unconsolidated affiliates	150	150
Other investments	12,652	10,432
Nonutility plant - net	1,558	1,628
Goodwill - net	5,557	5,557
Regulatory assets	95,303	52,106
Other assets	28,078	11,512
TOTAL ASSETS	**$ 2,224,512**	**$ 2,139,658**

The accompanying notes are an integral part of these financial statements

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

	December 31,	
	2017	2016
LIABILITIES & SHAREHOLDER'S EQUITY		
Common shareholder's equity		
Common stock (no par value)	$ 313,290	$ 313,290
Retained earnings	557,119	532,127
Total common shareholder's equity	**870,409**	**845,417**
Long-term debt payable to third parties - net of current maturities	288,517	239,233
Long-term debt payable to Utility Holdings - net of current maturities	333,512	365,561
Total long-term debt	**622,029**	**604,794**
Commitments & Contingencies (Notes 5, 7-10)		
Current Liabilities		
Accounts payable	42,394	50,053
Payables to other Vectren companies	6,034	12,011
Accrued liabilities	50,875	42,934
Short-term borrowings payable to Utility Holdings	1,718	—
Current maturities of long-term debt	—	49,140
Current maturities of long-term debt payable to Utility Holdings	61,880	—
Total current liabilities	**162,901**	**154,138**
Deferred Credits & Other Liabilities		
Deferred income taxes	195,252	382,622
Regulatory liabilities	265,239	54,555
Deferred credits & other liabilities	108,682	98,132
Total deferred credits & other liabilities	**569,173**	**535,309**
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**$ 2,224,512**	**$ 2,139,658**

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,	
	2017	2016
OPERATING REVENUES		
Electric utility	$ 569,587	$ 605,835
Gas utility	92,396	86,789
Total operating revenues	**661,983**	**692,624**
OPERATING EXPENSES		
Cost of fuel & purchased power	171,794	183,661
Cost of gas sold	33,949	32,000
Other operating	188,305	190,179
Depreciation & amortization	100,792	97,310
Taxes other than income taxes	17,728	19,238
Total operating expenses	**512,568**	**522,388**
OPERATING INCOME	**149,415**	**170,236**
Other income – net	6,032	5,309
Interest expense	31,410	31,788
INCOME BEFORE INCOME TAXES	**124,037**	**143,757**
Income taxes	44,110	53,563
NET INCOME	**$ 79,927**	**$ 90,194**

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, 2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 79,927	$ 90,194
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	100,792	97,310
Deferred income taxes & investment tax credits	10,241	22,504
Expense portion of pension & postretirement periodic benefit cost	2,382	1,729
Provision for uncollectible accounts	2,303	1,958
Other non-cash charges - net	710	1,434
Changes in working capital accounts:		
Accounts receivable, including due from Vectren companies & accrued unbilled revenues	(10,059)	(18,114)
Inventories	(957)	4,489
Recoverable/refundable fuel & natural gas costs	(2,791)	(11,326)
Prepayments & other current assets	3,417	2,992
Accounts payable, including to Vectren companies & affiliated companies	(11,662)	10,037
Accrued liabilities	7,941	2,144
Contributions to pension & postretirement plans	—	(6,300)
Changes in noncurrent assets	(26,097)	(6,423)
Changes in noncurrent liabilities	1,011	(9,590)
Net cash from operating activities	**157,158**	**183,038**
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from long-term debt, net of issuance costs	29,375	28
Requirements for:		
Dividends to Utility Holdings	(54,935)	(69,169)
Retirement of long-term debt	—	(13,000)
Net change in short-term borrowings, including from Utility Holdings	1,718	—
Net cash from financing activities	**(23,842)**	**(82,141)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from other investing activities	2,741	15,250
Requirements for capital expenditures, excluding AFUDC equity	(153,710)	(155,071)
Net change in short-term intercompany notes receivable	17,496	33,728
Changes in restricted cash	933	4,995
Net cash from investing activities	**(132,540)**	**(101,098)**
Net change in cash & cash equivalents	776	(201)
Cash & cash equivalents at beginning of period	1,499	1,700
Cash & cash equivalents at end of period	$ 2,275	$ 1,499

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, 2016	**$ 313,290**	**$ 511,102**	**$ 824,392**
Net income		90,194	90,194
Common stock:			
Dividends to Utility Holdings		(69,169)	(69,169)
Balance at December 31, 2016	**$ 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**

The accompanying notes are an integral part of these financial statements

1. Organization and Nature of Operations

Southern Indiana Gas and Electric Company (the Company, or SIGECO), an Indiana corporation, provides energy delivery services to approximately 145,200 electric customers and approximately 111,500 gas customers located near Evansville in southwestern Indiana. Of these customers, approximately 84,800 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.

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 29, 2018.

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 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* is 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. There were no impairments related to property, plant and equipment during the periods presented.

<u>Goodwill</u>
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.

<u>Regulation</u>
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 is recognized currently in earnings unless specific hedge criteria are met.

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, 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 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, related derivative activity is not material to these financial statements.

Revenues

Revenues are recorded as products and services are delivered to customers. To more closely match revenues and expenses, the Company records revenues for all gas and electricity delivered to customers but not billed at the end of an accounting period in *Accrued unbilled revenues*.

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 $8.6 million in 2017 and $9.1 million in 2016. 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 5).

3. Utility Plant & Depreciation

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

	At and For the Year Ended December 31,			
(In thousands)	2017		2016	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Electric utility plant	$ 2,833,503	3.3%	$ 2,751,967	3.3%
Gas utility plant	426,934	2.8%	385,796	2.8%
Common utility plant	59,059	3.2%	56,260	3.2%
Construction work in progress	47,556	—	32,166	—
Asset retirement obligations	50,402	—	53,134	—
Total original cost	**$ 3,417,454**		**$ 3,279,323**	

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, 2017, is $191.0 million with accumulated depreciation totaling $119.7 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*.

4. Regulatory Assets & Liabilities

Regulatory Assets
Regulatory assets consist of the following:

	At December 31,	
(In thousands)	2017	2016
Future amounts recoverable from ratepayers related to:		
Asset retirement obligations & other	$ 20,601	$ —
Net deferred income taxes	2,517	(13,037)
	23,118	(13,037)
Amounts deferred for future recovery related to:		
Cost recovery riders & other	32,429	20,309
	32,429	20,309
Amounts currently recovered through customer rates related to:		
Authorized trackers	20,277	17,897
Deferred coal costs	14,136	21,205
Unamortized debt issue costs, reacquisition premiums & hedging proceeds	5,343	5,732
	39,756	44,834
Total regulatory assets	**$ 95,303**	**$ 52,106**

Of the $39.8 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 $5.3 million, is 22 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, 2017 and 2016, the Company had *Regulatory liabilities* of approximately $265.2 million and $54.6 million, respectively, of which cost of removal obligations represented $55.4 million and $54.2 million, respectively, and at December 31, 2017, $209.4 million related to excess deferred income taxes. The deferred income tax regulatory liability is the result of the revaluation of deferred taxes at December 31, 2017 at the reduced federal corporate tax rate. These regulatory liabilities are expected to be refunded to customers over time following state regulator approval.

5. 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 $22.3 million in 2017 and $11.4 million in 2016. Amounts owed to VISCO at December 31, 2017 and 2016 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 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 $56.9 million and $52.3 million for the years ended December 31, 2017, and 2016, respectively. Amounts owed to Vectren and the Company's parent at December 31, 2017 and 2016 are included in *Payables to other Vectren companies*.

Retirement Plans & Other Postretirement Benefits

At December 31, 2017, 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. In 2016, the Company contributed $6.3 million to Vectren's defined benefit pension plans. No contributions were made in 2017. The combined funded status of Vectren’s plans was approximately 92 percent at December 31, 2017 and 2016.

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. For the years ended December 31, 2017 and 2016, costs totaling $3.7 million and $2.7 million, respectively, were charged to the Company.

Any difference between funding requirements and allocated periodic costs is recognized by the Company as an asset or liability. Neither plan assets nor plan obligations as calculated pursuant to GAAP are allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. The allocation methodology is consistent with FASB guidance related to “multiemployer” benefit accounting.

As of December 31, 2017 and 2016, the Company had $27.3 million and $7.1 million, respectively, included in *Other Assets* representing defined benefit pension funding by the Company that is yet to be reflected in costs. As of December 31, 2017 and 2016, the Company had $20.9 million and $16.7 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 funding of the defined benefit retirement and other postretirement plans, 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, 2017 and 2016, $26.7 million and $20.6 million, respectively, is included in *Accrued liabilities* and *Deferred credits & other liabilities* and represents obligations that are yet to be funded to Vectren.

Cash Management Arrangements

The Company participates in the centralized cash management program of the Company's parent. See Note 6 regarding long-term and short-term intercompany borrowing arrangements.

Guarantees of Parent Company Debt

The parent company's three operating utility companies, 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 $180 million is outstanding at December 31, 2017, and its $1.2 billion in unsecured senior notes outstanding at December 31, 2017. The majority of the unsecured senior notes 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.

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 parent company 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 in accordance with the regulatory treatment. 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.

In addition, the reduction in the federal corporate rate resulted in $150.2 million in excess federal deferred income taxes that have been classified as a regulatory liability.

The Company's gas and electric utilities currently recover corporate income tax expense in Commission 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 assets and liabilities to record all estimated impacts of tax reform starting January 1, 2018. The Company is complying with the order. The IURC held an initial conference of parties on February 6, 2018, and an order was issued by the Commission on February 16, 2018, outlining the process the utility companies are to follow. In accordance with the order, the Company filed on March 26, 2018 for proposed changes to its rates and charges to consider the impact of the lower corporate federal income tax rate. The proceeding, if unchallenged, will result in new rates by the beginning of May 2018.

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

	Year Ended December 31,	
(In thousands)	2017	2016
Current:		
Federal	$ 27,462	$ 23,635
State	6,407	7,424
Total current tax expense	**33,869**	**31,059**
Deferred:		
Federal	10,179	22,001
State	467	932
Total deferred tax expense	**10,646**	**22,933**
Amortization of investment tax credits	(405)	(429)
Total income tax expense	**$ 44,110**	**$ 53,563**

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

	Year Ended December 31,	
	2017	2016
Statutory rate	35.0 %	35.0 %
State & local taxes, net of federal benefit	4.2	4.4
Amortization of investment tax credit	(0.3)	(0.3)
Domestic production deduction	(2.1)	(1.0)
All other - net	(1.2)	(0.8)
Effective tax rate	**35.6 %**	**37.3 %**

Significant components of the net deferred tax liability follow:

	At December 31,	
(In thousands)	2017	2016
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$ 233,435	$ 361,128
Regulatory assets recoverable through future rates	4,635	11,388
Employee benefit obligations	(618)	7,575
Regulatory liabilities to be settled through future rates	(53,284)	(11,334)
Deferred fuel costs	9,570	14,289
Other – net	1,514	(424)
Net deferred tax liability	**$ 195,252**	**$ 382,622**

At December 31, 2017 and 2016, investment tax credits totaling $1.1 million and $1.5 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 $0.2 million at both December 31, 2017 and 2016.

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) has concluded examinations of Vectren's U.S. federal income tax returns for tax years through December 31, 2012. The State of Indiana, Vectren's primary state tax jurisdiction, has conducted examinations of state income tax returns for tax years through December 31, 2010. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2014 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 Indiana income tax returns will expire in 2020. The statutes of limitations for assessment of the 2009 and 2011 through 2014 tax years related to the amended Indiana income tax returns will expire in 2018 through 2020. On February 28, 2018, the Company was notified by the Indiana Department of Revenue that the Company was selected for a routine compliance audit for the tax periods January 1, 2015 through December 31, 2017.

Indiana Senate Bill 1

In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate has been lowered by 0.25 percent each year for the first five years and 0.35 percent in year six that began on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

6. Borrowing Arrangements & Other Financing Transactions

Short-Term Borrowings

The Company relies on the short-term borrowing arrangements of the parent company for its short-term working capital needs. There were $1.7 million and no borrowings outstanding at December 31, 2017 and 2016, respectively. The intercompany credit line totals $400 million, but is limited to the available capacity of the Company's parent ($220 million at December 31, 2017) 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 parent company's weighted average daily cost of short-term funds.

See the table below for interest rates and outstanding balances:

	Intercompany Borrowings	
(In thousands)	2017	2016
Year End		
Balance Outstanding	$ 1,718	$ —
Weighted Average Interest Rate	1.91%	1.05%
Annual Average		
Balance Outstanding	$ 249	$ —
Weighted Average Interest Rate	1.47%	—%
Maximum Month End Balance Outstanding	$ 1,718	$ —

Long-Term Debt

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

	At December 31,	
(In thousands)	2017	2016
Fixed Rate Senior Unsecured Notes Payable to Utility Holdings:		
2018, 5.75%	61,880	61,880
2020, 6.28%	74,596	74,596
2021, 4.67%	54,612	54,612
2023, 3.72%	24,847	24,847
2028, 3.20%	26,856	26,856
2035, 6.10%	25,284	25,285
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	—
2055, 4.51%	16,580	16,580
Total long-term debt payable to Utility Holdings	**$ 395,392**	**$ 365,561**
Current maturities	(61,880)	—
Total long-term debt payable to Utility Holdings	**$ 333,512**	**$ 365,561**
First Mortgage Bonds Payable to Third Parties:		
2022, 2013 Series C, current adjustable rate 1.565%, tax exempt	4,640	4,640
2024, 2013 Series D, current adjustable rate 1.565%, tax exempt	22,500	22,500
2025, 2014 Series B, current adjustable rate 1.565%, tax exempt	41,275	41,275
2029, 1999 Senior Notes, 6.72%	80,000	80,000
2037, 2013 Series E, current adjustable rate 1.565%, tax exempt	22,000	22,000
2038, 2013 Series A, 4.00%, tax exempt	22,200	22,200
2043, 2013 Series B, 4.05%, 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**
Current maturities	—	(49,140)
Debt issuance cost	(3,675)	(3,754)
Unamortized debt premium, discount & other - net	(473)	(538)
Total long-term debt payable to third parties - net	**$ 288,517**	**$ 239,233**

Issuance payable to the Company's Parent

On July 14, 2017, the Company's parent entered into a private placement Note Purchase Agreement pursuant to which institutional investors agreed to purchase the following tranches of notes: (i) $100 million of 3.26 percent Guaranteed Senior Notes, Series A, due August 28, 2032 and (ii) $100 million of 3.93 percent Guaranteed Senior Notes, Series B, due November 29, 2047. The notes are jointly and severally guaranteed by the Company, SIGECO, and VEDO. The Series A note proceeds were received on August 28, 2017 and the Series B proceeds were received on November 29, 2017. In December 2017, $29.8 million of this debt was reloaned to the Company.

SIGECO Variable Rate Tax-Exempt Bonds

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

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

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

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

The Purchase and Covenants Agreement provides the option, subject to satisfaction of customary conditions precedent, for the lenders to purchase from the Company and for the Company to convert to a variable rate other currently outstanding fixed rate, tax-exempt bonds that are callable at the Company's option in March 2018 (2013 Series A Notes totaling $22.2 million due March 1, 2038) and May 2018 (2013 Series B Notes totaling $39.6 million due by May 1, 2043). On March 1, 2018, the Company exercised its call option on the $22.2 million 2013 Series A Notes and refinanced those notes through the Purchase and Covenants agreement.

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 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.

SIGECO Bond Retirement

On June 1, 2016, a $13 million bond matured. The First Mortgage Bond, which was a portion of an original $25 million public issuance sold on June 1, 1986, carried a fixed interest rate of 8.875 percent. The repayment of debt was funded from the commercial paper program of the Company's parent.

Mandatory Tenders

At December 31, 2017, certain series of SIGECO bonds, aggregating $124.0 million are subject to mandatory tenders prior to the bonds' final maturities. $38.2 million will be tendered in 2020 and $85.8 million will be tendered in 2023.

Call Options

At December 31, 2017, certain series of SIGECO bonds, aggregating $84.1 million may be called at SIGECO's option. $22.2 million was called on March 1, 2018 and $39.6 million is callable on May 1, 2018. $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 2017 sinking fund requirement by this means and expects to also meet this requirement in 2018 in this manner. Accordingly, the sinking fund requirement is excluded from *Current liabilities* in the *Balance Sheets*. At December 31, 2017, $1.5 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 $3.4 billion at December 31, 2017.

Maturities of long-term debt during the five years following 2017 (in millions) are $61.9 in 2018, $74.6 in 2020, $54.6 in 2021, $4.6 in 2022 and $492.4 thereafter. There are no maturities of long-term debt in 2019.

<u>Covenants</u>

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, 2017, the Company was in compliance with all financial debt covenants.

7. Commitments & Contingencies

Purchase Commitments

The Company has firm commitments to purchase natural gas for up to a six 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, 2017, letters of credit outstanding total $8.4 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.

8. Electric Rate & Regulatory Matters

Electric Requests for Recovery under Senate Bill 560

The provisions of Senate Bill 560, as described in the Gas Rate & Regulatory Matters footnote for gas projects, are the same for qualifying electric projects. On February 23, 2017, the Company filed for authority to recover costs related to its electric system modernization plan, using the mechanism allowed under Senate Bill 560. The electric system modernization plan includes investments to upgrade portions of the Company's network of substations, transmission and distribution systems, to enhance reliability and allow the grid to accept advanced technology to improve the information and service provided to customers. The filing requested the recovery of associated capital expenditures estimated to be approximately $500 million over the seven-year period beginning in 2017.

On September 20, 2017, the IURC issued an Order approving the settlement agreement reached between the Company, the OUCC and a coalition of industrial customers on May 18, 2017. The settlement agreement reduced the plan spend to $446 million, with defined annual caps on recoverable capital investments. The majority of the reduction relating to the removal of advanced metering infrastructure (AMI or digital meters) from the plan. However, deferral of the costs for AMI was agreed upon in the settlement whereby the company can move forward with deployment in the near-term. In removing it from the plan, the request for cost recovery for the AMI project will not occur until the next base rate review proceeding, which would be expected to be filed by the end of 2023. The settlement agreement also addresses how the eligible costs would be recoverable in rates, with a cap on the residential and small general service fixed monthly charge per customer in each semi-annual filing. The remaining costs to residential and small general service customers would be recovered via a volumetric energy charge. The settlement agreement also addresses that semi-annual filings are to be made August 1, based on capital investments and expenses through the period ended April 30, and February 1, based on capital investments and expenses through October 31.

On August 1, 2017, the Company filed with the IURC its initial request for approval of the revenue requirement associated with a capital investment of $7.1 million through April 30, 2017. 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. On February 1, 2018, the Company submitted its second semi-annual filing, seeking approval of the recovery in rates of investments made of approximately $31 million through October 31, 2017. As of December 31, 2017, the Company has regulatory assets related to the Electric TDSIC plan totaling $4.3 million.

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

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

As of December 31, 2017, $30 million has been spent on equipment to control mercury in both air and water emissions, and $40 million to address the issues raised in the NOV. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. These costs will be included for recovery no later than the next rate case. The initial phase of the projects went into service in 2014, with the remaining investment going into service in 2016. As of December 31, 2017, the Company has approximately $12.8 million deferred related to depreciation and operating expenses, and $4.7 million deferred related to post-in-service carrying costs. MATS compliance was required beginning April 16, 2015, and the Company continues to operate in full compliance with the MATS rule.

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

On February 20, 2018, 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. No procedural schedule has been set, but the Company would expect an order in the first quarter of 2019.

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, most of the Company’s eligible industrial customers have since opted out of participation in the applicable energy efficiency programs.

Indiana Senate Bill 412 (Senate Bill 412) requires electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also requires the recovery of all program costs, including lost revenues and financial incentives associated with those plans and approved by the IURC. The Company made its first filing pursuant to this bill in June 2015, which proposed energy efficiency programs for calendar years 2016 and 2017. On March 23, 2016, the IURC issued an Order approving the Company's 2016-2017 energy efficiency plan. The Order provided for cost recovery of program and administrative expenses and included performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that 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. An appeal schedule has not been set, and while no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission's order, the Company expects to prevail in this appeal.

On April 10, 2017, the Company submitted its request for approval to the IURC of its Energy Efficiency Plan for calendar years 2018 through 2020. Consistent with prior filings, this filing included a request for continued cost recovery of program and administrative expenses, including performance incentives for reaching energy savings goals and continued recovery of lost margins consistent with the modified proposal in the 2016-2017 plan. Filed testimony of intervening parties was received on July 26, 2017, opposing the Company's proposed lost margin recovery. An evidentiary hearing was held in September 2017. On December 28, 2017, the Commission issued an order approving the 2018 through 2020 Plan, inclusive of recovery of lost margins consistent with the Order issued on December 20, 2017. On January 26, 2018, certain intervening parties initiated an appeal to the Indiana Court of Appeals. An appeal schedule has not been set, and while no assurance as to the ultimate outcome can be provided, based upon the record of the proceedings, as well as the findings in the Commission's order, the Company expects to prevail in this appeal.

For the twelve months ended December 31, 2017 and 2016, the Company recognized electric utility revenue of $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 a final order authorizing a 10.32 percent base ROE for the first refund period and prospectively through the date of the order in a second complaint case as detailed below.

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

Separately, on January 6, 2015, the FERC approved a MISO transmission owner joint request for an adder to the approved ROE. Under FERC regulations, transmission owners that are part of a Regional Transmission Organization (RTO) such as the

MISO are authorized to earn an incentive of 50 basis points above the FERC approved ROE. The adder is applied retroactively from January 6, 2015 through May 11, 2016 and prospectively from the September 28, 2016 order in the first complaint case.

The Company has reflected these results in its financial statements. As of December 31, 2017, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $133.5 million at December 31, 2017.

On April 14, 2017, the U.S. Court of Appeals for the District of Columbia circuit vacated the FERC Opinion in a prior case that established a new methodology for calculating ROE. This methodology was utilized in the final order in the Company's first complaint case, and the initial decision in the Company's second complaint case. The Appeals Court stated that FERC did not prove the existing ROE was not just and reasonable, failed to provide any reasoned basis for their selected ROE, and remanded to the FERC for further justification of its ROE calculation. The Company will continue to monitor this proceeding and evaluate any potential impacts on the Company's complaint cases but would not expect them to be material.

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 resource plans.

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 Commission 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 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 $90 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. The Company expects an order from the Commission in this proceeding by the first half of 2019.

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. The Company will seek authority from the IURC pursuant to Senate Bill 29 to recover the costs associated with the project in the second quarter of 2018.

In addition, the Company intends to continue to offer energy efficiency programs annually. Similarly, as discussed in more detail below, the extension of preliminary compliance deadlines related to ELG implementation are not expected to have a significant impact on the Company’s long term preferred generation plan.

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

9. Gas Rate & Regulatory Matters

<u>Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement</u>
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, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred for future recovery in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Recovery and Deferral Mechanisms
The Company's last gas utility rate order was received in 2007. This Order authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The Order provides for the deferral of depreciation and post-in-service carrying costs on qualifying projects totaling $3 million annually. The debt-related post-in-service carrying costs are currently recognized in the *Statements of Income*. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service. At both December 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $2.3 million, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are part of the Company’s seven-year capital investment plan discussed below.

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 two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses, with 80 percent of the costs, including a return, recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines to annually update the seven year capital investment plan. Finally, the Order approved the Company’s proposal to recover eligible costs assigned to the residential customer class via a fixed monthly charge per residential customer.

On January 24, 2018, the IURC issued an order (January 2018 order) approving the inclusion in rates of investments made from January 2017 to June 2017. Through the January 2018 Order, approximately $113 million of the approved capital investment has been incurred and included for recovery. The January 2018 Order also approved the Company's plan update, which now totals $242 million through 2020.

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 request includes approximately $7 million of operating expenses and $8 million of capital investments over a four-year period beginning in 2018. The Company received the IURC Order approving the request for recovery on December 28, 2017.

At December 31, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $16.4 million and $12.3 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 particular focus on extending integrity management rules to address a much larger portion of the natural gas infrastructure and adds requirements to address broader threats to the integrity of a pipeline system. The Company continues to evaluate the impact these proposed rules will have on its integrity management programs and transmission and distribution systems. Progress on finalizing the rule continues to work through the administrative process. The rule is expected to be finalized in 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.

10. 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 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 plant 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 $450 million grid modernization program, and is set forth in more detail in the Company’s upcoming 2018 corporate sustainability report.

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

The Company is subject to extensive environmental regulation pursuant to a variety of federal, state, and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting 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. As it relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act, was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August, the EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. On March 15, 2018, EPA published its proposed reconsideration of certain provisions of the existing CCR rule to bring the rule consistent with the WIIN Act. Vectren does not anticipate the reconsideration to change its current plans for pond closure as announced in its generation transition plan. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect.

Under the existing CCR rule, the Company is required to complete a series of integrity assessments, including seismic modeling given the Company’s facilities are located within two seismic zones, and groundwater monitoring studies to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place, with bottom ash handling conversions completed. In late 2015, using general utility industry data, the Company prepared cost estimates for the retirement of the ash ponds at the end of their useful lives, based on its interpretation of the closure alternatives contemplated in the final rule. The resulting estimates ranged from approximately $35 million to $80 million. These estimates contemplated final capping and monitoring costs of the ponds at both F.B. Culley and A.B. Brown generating stations. These rules are not applicable to the Company's Warrick generating unit, as this unit has historically been part of a larger generating station that predominantly serves an adjacent industrial facility.

Throughout 2016 and 2017, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $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, 2017, the Company had recorded an approximate $40 million asset retirement obligation (ARO). The recorded ARO reflects the present value of the approximate $45 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

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

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 ELGs setting stringent

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

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company's preferred IRP to be retired prior to December 31, 2023, the Company has requested those plants would not require new treatment technology, which was approved by IDEM provided the Company notifies IDEM within one year of issuance of the renewal of its intent to retire the unit. For the F.B. Culley 3 plant, the Company requested a 2020 compliance date for dry bottom ash and 2023 compliance date for flue gas desulfurization wastewater, which was approved by IDEM and finalized in the permit renewal. Discussion of these environmental investments at the F.B. Culley 3 plant are included in the generation transition plan in Footnote 8 Electric Rate & Regulatory Matters.

On April 13, 2017, as part of the Administration's regulatory reform initiative, which is focused on the number and nature of regulations, the EPA granted petitions to reconsider the ELG rule, and indicated it would stay the current implementation deadlines in the rule during the pendency of the reconsideration. The EPA has also sought a stay of the current judicial review litigation in federal district court. The court has yet to grant the indefinite stay sought by EPA, and instead placed the parties on a periodic status update schedule. On September 13, 2017, EPA finalized a rule postponing certain interim compliance dates by two years, but did not postpone the final compliance deadline of December 31, 2023. As the Company does not currently have short-term ELG implementation deadlines in its recently renewed wastewater discharge permits, the Company does not anticipate immediate impacts from the EPA's 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 preferred generation 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. 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.

<u>Air Quality</u>

Ozone NAAQS

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

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

Climate Change and Carbon Strategy

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which required a 32 percent reduction in carbon emissions from 2005 levels. This would result in a final emission rate goal for Indiana of 1,242 lb CO2/MWh to be achieved by 2030 and implemented through a state implementation plan. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA's reconsideration of the CPP rule, which was granted on April 28, 2017. Moreover, as indicated above, in October, 2017, EPA published its proposal to repeal the CPP. Comments to the repeal proposal are 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 are similarly due in April 2018. Repeal without replacement of the CPP could create potential litigation risk arising from the absence of direct federal regulation in this area that courts have previously determined preempt common law nuisance claims.

Impact of Legislative Actions & Other Initiatives is Unknown
At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. 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 $20.3 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 approximately $15.7 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company 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, 2017 and December 31, 2016, approximately $1.1 million and $1.4 million, respectively, of accrued, but not yet spent, costs are included in *Other Liabilities* related to these sites.

11. 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,			
	2017		2016	
(In thousands)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt payable to third parties	$ 288,517	$ 307,685	$ 288,373	$ 305,394
Long-term debt payable to Utility Holdings	395,392	418,102	365,561	387,618
Short-term borrowings payable to Utility Holdings	1,718	1,718	—	—
Short-term notes receivable from Utility Holdings	—	—	17,496	17,496
Natural gas purchase instrument liabilities (1)	354	354	—	—
Interest rate swap liabilities (2)	1,368	1,368	—	—
Cash & cash equivalents	2,275	2,275	1,499	1,499

(1) Presented in "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 on the 2013 Series A, B, and E Notes, as described in Note 6, through final maturity dates. 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. 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.

12. Additional Balance Sheet & Operational Information

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

	At December 31,	
(In thousands)	2017	2016
Materials & supplies	$ 32,681	$ 33,605
Fuel (coal and oil) for electric generation	43,086	42,590
Gas in storage – at LIFO cost	17,505	16,120
Total inventories	**$ 93,272**	**$ 92,315**

Based on the average cost of gas purchased during December 2017 and 2016, the cost of replacing gas in storage carried at LIFO cost is less than the carrying value at December 31, 2017 and 2016 by approximately $4 million and $3 million, respectively. All other inventories are carried at average cost. The Company purchases most of its coal supply from Sunrise Coal, LLC and most of its gas supply from a 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:

	At December 31,	
(In thousands)	2017	2016
Prepaid taxes	$ 375	$ 3,446
Wholesale emission allowances	203	230
Restricted cash	—	932
Other	1,096	1,312
Total prepayments & other current assets	**$ 1,674**	**$ 5,920**

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

	At December 31,	
(In thousands)	2017	2016
Accrued taxes	$ 18,600	$ 10,980
Customers advances & deposits	16,379	15,920
Accrued interest	5,253	5,338
Tax collections payable	2,859	2,533
Accrued salaries & other	7,784	8,163
Total accrued liabilities	**$ 50,875**	**$ 42,934**

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

(In thousands)	2017	2016
Asset retirement obligation, January 1	$ 61,796	$ 43,651
Accretion	2,077	1,833
Liabilities incurred in current period	—	—
Changes in estimates, net of cash payments	(2,731)	16,312
Asset retirement obligation, December 31	**$ 61,142**	**$ 61,796**

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

	Year ended December 31,	
(In thousands)	2017	2016
AFUDC – borrowed funds	$ 3,758	$ 3,352
AFUDC – equity funds	2,030	1,449
Other	244	508
Total other income - net	**$ 6,032**	**$ 5,309**

Supplemental Cash Flow Information:

	Year ended December 31,	
(In thousands)	2017	2016
Cash paid (received) for:		
Income taxes	$ 22,206	$ 37,916
Interest	31,496	31,696

As of December 31, 2017 and 2016, the Company has accruals related to utility plant purchases totaling approximately $9.2 million and $8.3 million, respectively.

13. Adoption of Other Accounting Standards

Revenue Recognition

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Company plans to adopt the guidance under the modified retrospective method. The cumulative effect adjustment to retained earnings will be immaterial.

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

The Company has finalized the assessment process of all revenue streams for the standard’s impact on the Balance Sheets, Statements of Operations, and disclosures and has identified all material revenue streams. The Company has determined that all material revenue streams fall under the scope of the standard. The standard will result in no significant changes to the Company's pattern of revenue recognition. The Company has adopted the guidance effective January 1, 2018.

Leases

In February 2016, the FASB issued new accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. This ASU requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. This ASU is effective for the interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach for leases that commenced prior to the date of adoption. The Company is currently evaluating the standard to determine the impact it will have on the financial statements and will adopt the guidance effective January 1, 2019.

Stock Compensation

In March 2016, the FASB issued new accounting guidance intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU was effective for annual periods beginning after December 15, 2016, and interim periods therein. The Company does not have share-based compensation plans separate from Vectren; the Company is however allocated costs associated with these plans. Pursuant to these plans, share based awards are settled via cash payments and are therefore not impacted by this standard. The adoption of this standard by the Company's parent did not have a material impact on the financial statements.

Presentation of Net Periodic Pension and Postretirement Benefit Costs

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

The ASU requires retrospective presentation of the service and non-service costs components in the income statement and prospective application regarding the capitalization of only the service cost component of net benefit costs. The Company has finalized its assessment of the standard and the adoption will have an immaterial impact on the financial statements. The Company has adopted the guidance effective January 1, 2018.

Other Recently Issued Standards

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

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The following discussion and analysis provides additional information regarding the Company's results of operations that is supplemental to the information provided in Vectren Corporation's and Utility Holdings' management's discussion and analysis of results of operations and financial condition contained in those 2017 annual reports filed on Form 10-K, which includes forward looking statement disclaimers. The following discussion and analysis should be read in conjunction with SIGECO's financial statements and notes thereto.

The Company generates revenue primarily from the delivery of natural gas and electric service to its customers, and the Company's primary source of cash flow results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services.

Vectren has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company's financial statements.

Executive Summary of Results of Operations

Operating Results

In 2017, the Company's earnings were $79.9 million compared to $90.2 million in 2016. Results in 2017 reflect the expected decrease in usage of a large electric customer that completed its transition to a co-generation facility and lower electric margins as both heating and cooling degree days in 2017 were lower than in 2016, partially offset by increased returns on the gas infrastructure replacement program.

The Regulatory Environment

Gas and electric operations, with regard to retail rates and charges, terms of service, accounting matters, financing, and certain other operational matters, are regulated by the IURC.

In the Company's natural gas service territory, normal temperature adjustment (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to residential and commercial customers due to weather and changing consumption patterns. In addition to these mechanisms, the commission has authorized gas and electric infrastructure replacement programs, which allow for recovery of these investments outside of a base rate case proceeding. Further, rates charged to natural gas customers contain a gas cost adjustment (GCA) clause and electric rates contain a fuel adjustment clause (FAC). Both of these cost tracker mechanisms allow for the timely adjustment in charges to reflect changes in the cost of gas and cost for fuel. The Company utilizes similar mechanisms for other material operating costs, which allow for changes in revenue outside of a base rate case. The implementation of these various mechanisms has allowed the Company to avoid regulatory proceedings to increase base rates since 2011 for its electric business and 2007 for its gas business.

Rate Design Strategies

Sales of natural gas and electricity to residential and commercial customers are largely seasonal and are impacted by weather. Trends in the average consumption among natural gas residential and commercial customers have tended to decline as more efficient appliances and furnaces are installed and the Company's utilities have implemented conservation programs. In the Company's natural gas service territory, NTA and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns.

In the Company's natural gas service territory, the commission has authorized bare steel and cast iron replacement programs. State laws were passed in 2012 and 2013 that expand the ability of utilities to recover, outside of a base rate proceeding, certain costs of federally mandated projects and other significant gas distribution and transmission infrastructure replacement investments. The Company has received approval to implement these mechanisms.

In 2017, the Company's electric service territory started recovering certain costs of electric distribution and transmission infrastructure replacement investments. The electric service territory also currently recovers certain transmission investments outside of base rates. The electric service territory has neither an NTA nor a decoupling mechanism; however, rate designs provide for a lost margin recovery mechanism that works in tandem with conservation initiatives.

Tracked Operating Expenses
Gas costs and fuel costs incurred to serve customers are two of the Company's most significant operating expenses. Rates charged to natural gas customers contain a GCA. The GCA clause allows the Company to timely charge for changes in the cost of purchased gas, inclusive of unaccounted for gas expense based on actual experience and subject to caps that are based on historical experience. Electric rates contain a FAC that allows for timely adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to an approved variable benchmark based on The New York Mercantile Exchange (NYMEX) natural gas prices, is also timely recovered through the FAC.

GCA and FAC procedures involve periodic filings and IURC hearings to establish price adjustments for a designated future period. The procedures also provide for inclusion in later periods of any variances between actual recoveries representing the estimated costs and actual costs incurred.

The IURC has also applied the statute authorizing GCA and FAC procedures to reduce rates when necessary to limit net operating income to a level authorized in its last general rate order through the application of an earnings test. In the periods presented, the Company has not been impacted by the earnings test.

Gas pipeline integrity management operating costs, costs to fund energy efficiency programs, MISO costs, and the gas cost component of uncollectible accounts expense based on historical experience are recovered by mechanisms outside of typical base rate recovery. In addition, certain operating costs, including depreciation associated with federally mandated investments, gas and electric distribution and transmission infrastructure replacement investments, and regional electric transmission assets not in base rates are also recovered by mechanisms outside of typical base rate recovery.

Revenues and margins are also impacted by the collection of state mandated taxes, which primarily fluctuate with gas and fuel costs.

Base Rate Orders
The Company's electric territory received an order in April 2011, with rates effective May 2011, and its gas territory received an order and implemented rates in August 2007. The orders authorize a return on equity of 10.40% on the electric operations and 10.15% for the gas operations. The authorized returns reflect the impact of rate design strategies that have been authorized by the IURC.

See Notes 8 and 9 to the financial statements for more specific information on the significant regulatory proceedings involving the Company.

Operating Trends

Margin

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

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

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

	Year Ended December 31,			
(In thousands)		2017		2016
Electric utility revenues	$	569,587	$	605,835
Cost of fuel & purchased power		171,794		183,661
Total electric utility margin	**$**	**397,793**	**$**	**422,174**
Margin attributed to:				
Residential & commercial customers	$	254,838	$	261,236
Industrial customers		96,913		112,087
Other		5,617		5,725
Regulatory expense recovery mechanisms		9,611		13,729
Subtotal: Retail	**$**	**366,979**	**$**	**392,777**
Wholesale margin		30,814		29,397
Total electric utility margin	**$**	**397,793**	**$**	**422,174**
Electric volumes sold in MWh attributed to:				
Residential & commercial customers		2,638,783		2,729,037
Industrial customers		2,096,523		2,722,320
Other customers		22,261		22,848
Total retail volumes		**4,757,567**		**5,474,205**
Wholesale		463,252		136,053
Total volumes sold		**5,220,819**		**5,610,258**

Retail
Electric retail utility margins were $367.0 million for the year ended December 31, 2017 and, compared to 2016, decreased by $25.8 million. Results reflect a decrease in large customer margin of $15.2 million, primarily due to the completion of a large customer transitioning to a cogeneration facility resulting in lower usage of approximately 610 GWh in 2017. Electric margin, which is not protected by weather normalizing mechanisms, reflects a $5.4 million decrease in customer margin related to weather as heating degree days were 80 percent of normal compared in 2017 compared to 84 percent of normal in 2016 and cooling degree days were 111 percent of normal compared to 125 percent of normal in 2016. Margin from regulatory expense recovery mechanism decreased $4.1 million in 2017.

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

	Year Ended December 31,			
(In thousands)		2017		2016
MISO transmission system margin	$	25,498	$	25,101
MISO off-system margin		5,316		4,296
Total wholesale margin	**$**	**30,814**	**$**	**29,397**

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $25.5 million during 2017, compared to $25.1 million in 2016. The Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $133.5 million at December 31, 2017. These projects include an interstate 345 kV transmission line that connects the Company's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric

Corporation to the south; a substation; and another transmission line. These projects earn a FERC approved equity rate of return on the net plant balance and recover operating expenses. In September 2016, the FERC issued a final order authorizing the transmission owners to receive a 10.32 percent base ROE plus, a separately approved 50 basis point adder, compared to the previously authorized 12.38 percent. The Company has reflected these outcomes in its financial statements. The 345 kV project is the largest of these qualifying projects, with an original cost of $106.8 million that earned the FERC approved equity rate of return.

For the year ended December 31, 2017, margin from off-system sales was $5.3 million, compared to $4.3 million in 2016. The base rate changes implemented in May 2011 require wholesale margin from off-system sales earned above or below $7.5 million per year is to be shared equally with customers. Results, net of sharing for the periods presented, were favorable in 2017 compared to 2016, reflecting higher market prices due primarily to higher natural gas prices.

Gas Utility Margin (Gas utility revenues less Cost of gas sold)
Gas utility margin and throughput by customer type follows:

	Year Ended December 31,	
(In thousands)	2017	2016
Gas utility revenues	$ 92,396	$ 86,789
Cost of gas sold	33,949	32,000
Total gas utility margin	**$ 58,447**	**$ 54,789**
Margin attributed to:		
Residential & commercial customers	$ 41,964	$ 39,265
Industrial customers	9,956	9,764
Other	1,004	1,169
Regulatory expense recovery mechanisms	5,523	4,591
Total gas utility margin	**$ 58,447**	**$ 54,789**
Sold & transported volumes in MDth attributed to:		
Residential & commercial customers	9,113	9,433
Industrial customers	28,771	34,377
Total sold & transported volumes	**37,884**	**43,810**

Gas Utility margin was $58.4 million for the year ended December 31, 2017, an increase of $3.6 million compared to 2016. The increase in margin was largely due to increased returns on the gas infrastructure replacement program. Weather has relatively no impact on customer margin due to the Company's rate design. The decrease in sold and transported volumes was primarily due to a large Industrial customer constructing a pipeline to serve their co-generation facility and other natural gas demands of their plant.

Operating Expenses

Other Operating
For the year ended December 31, 2017, *Other operating* expenses were $188.3 million, decreasing $1.9 million compared to 2016. Excluding operating expenses recovered through margin, which decreased $3.3 million, operating expenses increased $1.4 million, primarily from higher performance-based compensation expense driven by an increase in Vectren's stock price.

Depreciation & Amortization
Depreciation and amortization expense was $100.8 million in 2017, compared to $97.3 million in 2016. The increase resulted from additional utility plant investments placed into service.

SELECTED ELECTRIC OPERATING STATISTICS

	For the Year Ended December 31, 2017	2016
OPERATING REVENUES (in thousands):		
Residential	$ 200,821	$ 209,287
Commercial	154,564	155,656
Industrial	162,586	197,284
Other	9,246	10,440
Total Retail	527,217	572,667
Net Wholesale Revenues	42,370	33,168
	$ 569,587	$ 605,835
MARGIN (In thousands):		
Residential	$ 148,555	$ 153,614
Commercial	106,283	107,622
Industrial	96,913	112,087
Other	5,617	5,725
Regulatory expense recovery mechanisms	9,611	13,729
Total Retail	366,979	392,777
Wholesale power & transmission system	30,814	29,397
	$ 397,793	$ 422,174
ELECTRIC SALES (In MWh):		
Residential	1,362,457	1,424,533
Commercial	1,276,326	1,304,504
Industrial	2,096,523	2,722,320
Other Sales - Street Lighting	22,261	22,848
Total Retail	4,757,567	5,474,205
Wholesale	463,252	136,053
	5,220,819	5,610,258
AVERAGE CUSTOMERS:		
Residential	126,443	125,662
Commercial	18,648	18,551
Industrial	112	113
Other	40	39
	145,243	144,365
WEATHER AS A % OF NORMAL:		
Cooling Degree Days	111%	125%
Heating Degree Days	80%	84%

SELECTED GAS OPERATING STATISTICS

	For the Year Ended December 31,	
	2017	2016
OPERATING REVENUES (In thousands):		
Residential	$ 60,097	$ 55,052
Commercial	21,428	21,247
Industrial	9,820	9,493
Other	1,051	997
	$ 92,396	$ 86,789
MARGIN (In thousands):		
Residential	$ 32,707	$ 30,459
Commercial	9,257	8,806
Industrial	9,956	9,764
Other	1,004	1,169
Regulatory expense recovery mechanisms	5,523	4,591
	$ 58,447	$ 54,789
GAS SOLD & TRANSPORTED (In MDth):		
Residential	5,860	6,101
Commercial	3,253	3,332
Industrial	28,771	34,377
	37,884	43,810
AVERAGE CUSTOMERS:		
Residential	101,064	100,672
Commercial	10,304	10,288
Industrial	112	112
	111,480	111,072

(Back To Top)

Section 3: EX-99.2 (EXHIBIT 99.2 - SIG 2017 REPORTING PACKAGE)

Exhibit 99.2

Forward-Looking Information

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

- *Factors affecting utility operations such as unfavorable or unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to coal and natural gas costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.*
- *New or proposed legislation, litigation and government regulation or other actions, such as changes in, rescission of or additions to tax laws or rates, pipeline safety regulation and environmental laws and regulations, including laws governing air emissions, carbon, waste water discharges and the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of generation plant costs and related assets. Compliance with respect to these regulations could substantially change the operation and nature of the Company's utility operations.*
- *Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, physical attacks, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.*
- *Approval and timely recovery of new capital investments related to the electric generation transition plan, discussed further herein, including timely approval to build and own generation, ability to meet capacity requirements, ability to procure resources needed to build new generation at a reasonable cost, ability to appropriately estimate costs of new generation, the effects of construction delays and cost overruns, ability to fully recover the investments made in retiring portions of the current generation fleet, scarcity of resources and labor, and workforce retention, development and training.*
- *Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.*
- *Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, interpretation of regulatory-related legislation by the IURC and/or PUCO and appellate courts that review decisions issued by the agencies, and the frequency and timing of rate increases.*
- *Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.*
- *Economic conditions including the effects of inflation, commodity prices, and monetary fluctuations.*
- *Economic conditions, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity; economic impacts of changes in business strategy on both gas and electric large customers; lower residential and commercial customer counts; variance from normal population growth and changes in customer mix; and higher operating expenses.*
- *Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.*
- *Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.*

- *Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.*
- *Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.*
- *Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.*
- *Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.*

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

(Back To Top)