VECTREN UTILITY HOLDINGS INC
Form 10-K
March 08, 2018

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017
OR

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

For the transition period from __________________ to ________________________

Commission file number: 1-16739

VECTREN UTILITY HOLDINGS, INC.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| INDIANA<br>(State or other jurisdiction of incorporation or organization) | 35-2104850<br>(IRS Employer Identification No.) |
| One Vectren Square<br>(Address of principal executive offices) | 47708<br>(Zip Code) |

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

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| Vectren Utility 6.10% SR NTS 12/1/2035 | New York Stock Exchange |

1

Securities registered pursuant to Section 12(g) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common – Without Par | None |

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
*Yes ý No ¨
*Utility Holdings is a majority owned subsidiary of a well-known seasoned issuer, and well-known seasoned issuer status depends in part on the type of security being registered by the majority-owned subsidiary.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨ Accelerated filer ¨

Non-accelerated filer ý Smaller reporting company ¨
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ¨ No ý

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2017, was zero. All shares outstanding of the Registrant's common stock were held by Vectren Corporation.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

| | | |
|---|---|---|
| Common Stock - Without Par Value | 10 | February 28, 2018 |
| Class | Number of Shares | Date |

2

Omission of Information by Certain Wholly Owned Subsidiaries

The Registrant is a wholly owned subsidiary of Vectren Corporation and meets the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K and is therefore filing with the reduced disclosure format contemplated thereby.

Definitions

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

Access to Information

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

| | | |
|---|---|---|
| Mailing Address:<br>One Vectren Square<br>Evansville, Indiana 47708 | Phone Number:<br>(812) 491-4000 | Investor Relations Contact:<br>David E. Parker<br>Director, Investor Relations vvcir@vectren.com |

3

Table of Contents



(A) – Omitted or amended as the Registrant is a wholly owned subsidiary of Vectren Corporation and meets the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K and is therefore filing with the reduced disclosure format contemplated thereby.

# PART I
## ITEM 1. BUSINESS

### Description of the Business

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

Indiana Gas provides energy delivery services to approximately 592,400 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 145,200 electric customers and approximately 111,500 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 318,100 natural gas customers located near Dayton in west-central Ohio.

### Narrative Description of the Business

The Company has regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations into a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment includes the operations of Indiana Gas, VEDO, and SIGECO’s natural gas distribution business and provides natural gas distribution and transportation services to nearly two-thirds of Indiana and about 20 percent of Ohio, primarily in the west-central area. The Electric Utility Services segment includes the operations of SIGECO’s electric transmission and distribution services, which provides electric transmission and distribution services to southwestern Indiana, and includes its power generating and wholesale power operations. In total, these regulated operations supply natural gas and electricity to over one million customers.

At December 31, 2017, the Company had $5.5 billion in total assets, with approximately $3.5 billion attributed to Gas Utility Services, $1.8 billion attributed to Electric Utility Services, and $0.2 billion attributed to Other Operations. Net income for the year ended December 31, 2017 and 2016, was $175.8 million and $173.6 million, respectively. For further information regarding the activities and assets of operating segments, refer to Note 13 in the Consolidated Financial Statements included in Item 8.

Following is a more detailed description of the Gas Utility Services and Electric Utility Services operating segments. Other Operations are not significant.

### Gas Utility Services

In 2017, the Company supplied natural gas service to approximately 1,022,000 Indiana and Ohio customers, including 934,800 residential, 85,500 commercial, and 1,700 industrial and other contract customers. Gas utility customers served were approximately 1,014,000 in 2016 and 1,004,800 in 2015.

The Company's service area contains diversified manufacturing and agriculture-related enterprises. The principal industries served include automotive assembly, parts and accessories; feed, flour and grain processing; metal castings, plastic products; gypsum products; electrical equipment, metal specialties, glass and steel finishing; pharmaceutical and nutritional products; gasoline and oil products; ethanol; and coal mining. The largest Indiana communities served are Evansville, Bloomington, Terre Haute, suburban areas surrounding Indianapolis and Indiana counties near Louisville, Kentucky. The largest community served outside of Indiana is Dayton, Ohio.

Revenues

The Company receives gas revenues by selling gas directly to customers at approved rates or by transporting gas through its pipelines at approved rates to customers that have purchased gas directly from other producers, brokers, or marketers. Total throughput was 219.3 MMDth for the year ended December 31, 2017. Gas sold and transported to residential and commercial customers was 97.1 MMDth representing 44 percent of throughput. Gas transported or sold to industrial and other contract customers was 122.2 MMDth representing 56 percent of throughput.

For the year ended December 31, 2017, gas utility revenues were $812.7 million, of which residential customers accounted for 67 percent and commercial accounted for 22 percent. Industrial and other contract customers accounted for 11 percent of revenues. Rates for transporting gas generally provide for the same margins earned by selling gas under applicable sales tariffs.

Availability of Natural Gas

The volume of gas sold is seasonal and affected by variations in weather conditions. To meet seasonal demand, the Company's Indiana gas utilities have storage capacity at eight active underground gas storage fields and three propane plants. Periodically, purchased natural gas is injected into storage. The injected gas is then available to supplement contracted and manufactured volumes during periods of peak requirements. The volumes of gas per day that can be delivered during peak demand periods for each utility are located in “Item 2 Properties.”

Natural Gas Purchasing Activity in Indiana
The Indiana utilities enter into short-term and long-term contracts with third party suppliers to purchase natural gas. Certain contracts are firm commitments under five and ten-year arrangements. During 2017, the Company, through its utility subsidiaries, purchased all of its gas supply from third parties and 67 percent was from a single third party.

Natural Gas Purchasing Activity in Ohio
On April 30, 2008, the PUCO issued an order which approved an exit from the merchant function in the Company's Ohio service territory. As a result, substantially all of the Company's Ohio customers purchase natural gas directly from retail gas marketers rather than from the Company. Exiting the merchant function has not had a material impact on earnings or financial condition.

Total Natural Gas Purchased Volumes
In 2017, the Company purchased 66.1 MMDth volumes of gas at an average cost of $4.02 per Dth inclusive of demand charges. The average cost of gas per Dth purchased for the previous four years was $3.75 in 2016, $3.96 in 2015, $5.42 in 2014, and $4.60 in 2013.

Electric Utility Services

In 2017, the Company supplied electric service to approximately 145,200 Indiana customers, including approximately 126,400 residential, 18,600 commercial, and 200 industrial and other customers. Electric utility customers served were approximately 144,400 in 2016; 143,600 in 2015.

The principal industries served include plastic products; automotive assembly and steel finishing; pharmaceutical and nutritional products; automotive glass; gasoline and oil products; ethanol; and coal mining.

Revenues

For the year ended December 31, 2017, retail electricity sales totaled 4,757.6 GWh, resulting in revenues of approximately $527.2 million. Residential customers accounted for 38 percent of 2017 revenues; commercial 29 percent; industrial 31 percent; and other 2 percent. In addition, in 2017 the Company sold 463.2 GWh through wholesale activities principally to the Midcontinent Independent System Operator (MISO). Wholesale revenues, including transmission-related revenue, totaled $42.4 million in 2017.

System Load

Total load for each of the years 2013 through 2017 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

| | | | | | |
|---|---|---|---|---|---|
| Date of summer peak load | 7/21/2017 | 6/22/2016 | 7/29/2015 | 8/27/2014 | 8/30/2013 |
| Total load at peak | 1,042 | 1,096 | 1,088 | 1,095 | 1,102 |
| | | | | | |
| Generating capability | 1,248 | 1,248 | 1,248 | 1,298 | 1,298 |
| Purchase supply (effective capacity) | 36 | 37 | 37 | 38 | 38 |
| Interruptible contracts & direct load control | 53 | 75 | 72 | 71 | 48 |
| Total power supply capacity | 1,337 | 1,360 | 1,357 | 1,407 | 1,384 |
| Reserve margin at peak | 28 % | 24 % | 25 % | 22 % | 25 % |

The winter peak load for the 2016-2017 season of approximately 822 MW occurred on December 15, 2016. The prior year winter peak load for the 2015-2016 season was approximately 868 MW, occurring on January 13, 2016.

Generating Capability

Installed generating capability as of December 31, 2017, was rated at 1,248 MW. Coal-fired generating units provide 1,000 MW of capacity, natural gas or oil-fired turbines used for peaking or emergency conditions provide 245 MW, and a landfill gas electric generation project provides 3 MW. Electric generation for 2017 was fueled by coal (97 percent), natural gas (2 percent), and landfill gas (less than 1 percent). Oil was used only for testing of gas/oil-fired peaking units. The Company generated approximately 4,578 GWh in 2017. Further information about the Company's owned generation is included in "Item 2 Properties."

Coal for coal-fired generating stations has been supplied from operators of nearby coal mines as there are substantial coal reserves in the southern Indiana area. Approximately 2.1 million tons were purchased for generating electricity during 2017. This compares to 1.9 million tons and 2.5 million tons purchased in 2016 and 2015, respectively. The Company's coal inventory was approximately 800 thousand tons at both December 31, 2017 and 2016.

Coal Purchases

The average cost of coal per ton purchased and delivered for the last five years was $53.88 in 2017, $54.24 in 2016, $55.22 in 2015, $55.18 in 2014, and $58.38 in 2013. Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal, LLC (Sunrise Coal), an Indiana-based wholly owned subsidiary of Hallador Energy Company, to modify existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts were assigned to Sunrise Coal and the Company purchases substantially all of its coal from Sunrise Coal.

Firm Purchase Supply

As part of its power portfolio, SIGECO is a 1.5 percent shareholder in the Ohio Valley Electric Corporation (OVEC), and based on its participation in the Inter-Company Power Agreement (ICPA) between OVEC and its shareholder companies, many of whom are regulated electric utilities, SIGECO has the right to 1.5 percent of OVEC's generating capacity output, which is approximately 32 MWs. Per the ICPA, SIGECO is charged demand charges which are based on OVEC's operating expenses, including its financing costs. Those demand charges are available to pass through to customers under SIGECO's fuel adjustment clause (FAC). Under the ICPA, and while OVEC's plants are operating, SIGECO is severally responsible for its share of OVEC's debt obligations. Based on OVEC's current financing, SIGECO's 1.5 percent share of OVEC's debt obligation equates to approximately $21 million. Recently, due to concerns regarding the potential default of one of OVEC's shareholders that holds a 4.9 percent interest under the ICPA, Moody's downgraded OVEC to Ba1 and Standard and Poor's revised its BBB- rating outlook from stable to negative. OVEC has represented it has both liquidity and financing capability that will allow it to continue to operate and provide power to its participating members, who include American Electric Power, Duke Energy, and PPL Corporation. In 2017, the Company purchased approximately 141 GWh from OVEC. If a default were to occur by a member, any reallocation of the existing debt requires consent of the remaining ICPA participants. If any such reallocation were to occur, SIGECO would expect to recover any related costs through the FAC, as it does currently for its 1.5 percent share.

In April 2008, the Company executed a capacity contract with Benton County Wind Farm, LLC to purchase as much as 30 MW from a wind farm located in Benton County, Indiana, with IURC approval. The contract expires in 2029. In 2017, the Company purchased approximately 78 GWh under this contract.

In December 2009, the Company executed a 20 year power purchase agreement with Fowler Ridge II Wind Farm, LLC to purchase as much as 50 MW of energy from a wind farm located in Benton and Tippecanoe Counties in Indiana, with the approval of the IURC. In 2017, the Company purchased 142 GWh under this contract. In total, wind resources provided 4 percent of total GWh sourced.

MISO Related Activity

The Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electric 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, where it bids its generation into the Day Ahead and Real Time markets and procures 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 as purchased power in Cost of fuel & purchased power and net sales in a single hour are recorded in Electric utility revenues. During 2017, in hours when purchases from the MISO were in excess of generation sold to the MISO, the net purchases were 494 GWh. During 2017, in hours when sales to the MISO were in excess of purchases from the MISO, the net sales were 463 GWh.

Interconnections

The Company has interconnections with Louisville Gas and Electric Company, Duke Energy Shared Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc., and Big Rivers Electric Corporation providing the ability to simultaneously interchange approximately 900 MW during peak load periods. The Company, as required as a member of the MISO, has turned over operational control of the interchange facilities and its own transmission assets to the MISO. The Company in conjunction with the MISO must operate the bulk electric transmission system in accordance with NERC Reliability Standards. As a result, interchange capability varies based on regional transmission system configuration, generation dispatch, seasonal facility ratings, and other factors. The Company is in compliance with reliability standards promulgated by the NERC. Additionally, the Company is audited against those standards from time to time with no material issues or findings to date.

Competition

See a discussion on competition within the utility industry in "Item 1A Risk Factors" which is incorporated by reference herein.

Regulatory, Environmental, and Sustainability Matters

See “Item 7 Management’s Discussion and Analysis of Results of Operations and Financial Condition” regarding the Company’s regulatory environment, environmental and sustainability matters.

Personnel

As of December 31, 2017, the Company and its consolidated subsidiaries had approximately 1,600 employees, of which 700 are subject to collective bargaining arrangements.

In July 2017, the Company reached a three-year labor agreement with Local 1393 of the International Brotherhood of Electrical Workers and United Steelworkers of America Locals 12213 and 7441, ending December 1, 2020. This labor agreement relates to employees of Indiana Gas.

In April 2016, the Company reached a three-year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 30, 2019. This labor agreement relates to employees of SIGECO.

In June 2015, the Company reached a three-year agreement with Local 175 of the Utility Workers Union of America, ending October 31, 2018. This labor agreement relates to employees of VEDO.

In May 2015, the Company reached a three-year agreement with Local 135 of the Teamsters, Chauffeurs, Warehousemen, and Helpers Union, ending September 23, 2018. This labor agreement relates to employees of SIGECO.

## ITEM 1A. RISK FACTORS

Investors should consider carefully the following factors that could cause the Company’s operating results and financial condition to be materially adversely affected.

The Company is a holding company and its assets consist primarily of investments in its subsidiaries.

The ability of the Company to pay dividends to the Company's parent and repay indebtedness depends on the earnings, financial condition, capital requirements and cash flow of its subsidiaries, SIGECO, Indiana Gas, and VEDO and the distribution of those earnings to the Company. Should the earnings, financial condition, capital requirements or cash flow of, or legal requirements applicable to them restrict their ability to pay dividends or make other payments to the Company, its ability to pay dividends to its parent could be limited. Results of operations, future growth, and earnings and dividend goals also will depend on the performance of its subsidiaries. Additionally, certain of the Company’s lending arrangements contain restrictive covenants, including the maintenance of a total debt to total capitalization ratio.

A deterioration of current economic conditions may have adverse impacts.

Economic conditions may have some negative impact on both gas and electric industrial and commercial customers. This impact may include volatility and unpredictability in the demand for natural gas and electricity, tempered growth strategies, significant conservation measures, and perhaps plant closures, production cutbacks, or bankruptcies. Economic conditions may also cause reductions in residential and commercial customer counts and lower revenues. It is also possible that an uncertain economy could affect costs including interest costs, uncollectible accounts expense, and allocated pension costs.

Financial market volatility could have adverse impacts.

The capital and credit markets may experience volatility and disruption. If market disruption and volatility occurs, there can be no assurance the Company will not experience adverse effects, which may be material. These effects may include, but are not limited to, difficulties in accessing the short and long-term debt capital markets and the commercial paper market, increased borrowing costs associated with short-term debt obligations, higher interest rates in future financings, and a smaller potential pool of investors and funding sources. Finally, there is no assurance the Company's parent will have access to the equity capital markets to obtain financing when necessary or desirable.

Change to United States laws, regulations, and policy may not have desired effects.

Policy and/or legislative changes in the areas of, among others, energy, comprehensive tax reform, environmental regulation, and/or infrastructure expenditures (including preference toward domestically sourcing expenditures) could have material impacts on the financial performance or condition of the Company. In addition the Company’s implementation of policy changes may or may not be received favorably by the Company’s stakeholders and/or government officials advocating policy change, both of which have reputational risk.

There have been substantial changes to the Internal Revenue Code, some of which may have impacts materially different than current estimates.

On December 22, 2017, the United States government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act ("the TCJA"), which significantly reforms the Internal Revenue Code ("IRC"). The estimated impact of the TCJA in these statements is based on management's current knowledge and assumptions and recognized impacts could be different from current estimates based on actual results and further analysis of the new law.

The Company has long-term and short-term debt guaranteed by its subsidiaries.

The Company currently has outstanding long-term and short-term debt that is jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. Such debt obligations are not guaranteed by the Company's parent.

A downgrade (or negative outlook) in or withdrawal of the Company's credit ratings could negatively affect its ability to access capital and its cost.

The following table shows the current ratings assigned to certain outstanding debt by Moody's and Standard & Poor's:

| | Current Rating | |
|---|---|---|
| | Moody's | Standard & Poor's |
| Utility Holdings and Indiana Gas senior unsecured debt | A2 | A- |
| Utility Holdings commercial paper program | P-1 | A-2 |
| SIGECO's senior secured debt | Aa3 | A |

The current outlook for both Moody's and Standard & Poor's is stable. Both rating agencies categorize the ratings of the above securities as investment grade. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard & Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

If the rating agencies downgrade the Company's credit ratings, particularly below investment grade, or initiate negative outlooks thereon, or withdraw the Company's ratings or, in each case, the ratings of its subsidiaries, it may significantly limit the Company's access to the debt capital markets and the commercial paper market, and the Company's borrowing costs would likely increase. In addition, the Company would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources would likely decrease. Finally, there is no assurance that the Company's parent will have access to the equity capital markets to obtain financing when necessary or desirable.

The Company will need to raise capital through additional debt financing.

The Company will need to raise additional capital in the future. Executing upon the Company's generation transition plan, as more fully discussed herein, will increase the need for the Company to raise additional capital. The Company may raise additional funds through debt offerings and any new debt financing the Company enters into may involve covenants that restrict the Company's operations more than current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of the Company's assets, as well as prohibitions or limitations on the Company's ability to create liens, pay dividends, receive distributions from subsidiaries, or make investments.

The Company may raise additional funds through equity offerings through its parent. There is no assurance the Company's parent will have access to the equity capital markets to obtain financing when necessary or desirable.

The Company's gas and electric utility sales are concentrated in the Midwest.

The operations of the Company’s regulated utilities are concentrated in central and southern Indiana and west-central Ohio and are therefore impacted by changes in the Midwest economy in general and changes in particular industries concentrated in the

Midwest. These industries include automotive assembly, parts and accessories; feed, flour and grain processing; metal castings, plastic products; gypsum products; electrical equipment, metal specialties, glass and steel finishing; pharmaceutical and nutritional products; gasoline and oil products; ethanol; and coal mining. Changing market conditions, including changing regulation, changes in market prices of oil or other commodities, or changes in government regulation and assistance, may cause certain industrial customers to reduce or cease production and thereby decrease consumption of natural gas and/or electricity.

The Company operates in an increasingly competitive industry, which may affect its future earnings.

The utility industry has been undergoing structural change for several years, resulting in increasing competitive pressure faced by electric and gas utility companies. Increased competition, including those from cogeneration, private generation, solar, and other renewables opportunities for customers, may create greater risks to the stability of the Company’s earnings generally and may in the future reduce its earnings from retail electric and gas sales. In this regard, the deployment and commercialization of technologies, such as private renewable energy sources, cogeneration facilities, and energy storage, have the potential to change the nature of the utility industry and reduce demand for the Company’s electric and gas products and services. If the Company is not able to appropriately adapt to structural changes in the utility industry as a result of the development of these technologies, this may have an adverse effect on the Company’s financial condition and results of operations. Additionally, several states, including Ohio, have passed legislation that allows customers to choose their electricity supplier in a competitive market. Indiana has not enacted such legislation. Ohio regulation also provides for choice of commodity providers for all gas customers. The Company has implemented this choice for its gas customers in Ohio. The state of Indiana has not adopted any regulation requiring gas choice in the Company’s Indiana service territories; however, the Company operates under approved tariffs permitting certain industrial and commercial large volume customers to choose their commodity supplier. The Company cannot provide any assurance that increased competition or other changes in legislation, regulation or policies will not have a material adverse effect on its business, financial condition or results of operations.

A significant portion of the Company’s electric utility sales are space heating and cooling.  Accordingly, its operating results may fluctuate with variability of weather.

The Company's electric utility sales are sensitive to variations in weather conditions. In this regard, many customers rely on electricity to heat and cool their homes and businesses and, as a result, the Company’s results of operations may be adversely affected by warmer-than-normal heating season weather or colder-than-normal cooling season weather. Accordingly, demand for electricity used for heating purposes is generally at its highest during the peak heating season of October through March and is directly affected by the severity of the winter weather. The Company forecasts utility sales on the basis of normal weather. Since the Company does not have a weather-normalization mechanism for its electric operations, significant variations from normal weather could have a material impact on its earnings. However, the impact of weather on the gas operations in the Company’s Indiana territories has been significantly mitigated through the implementation of a normal temperature adjustment mechanism. Additionally, the implementation of a straight fixed variable rate design mitigates most weather variations related to Ohio residential and commercial gas sales.

The Company’s businesses are exposed to increasing regulation, including pipeline safety, environmental, and cybersecurity regulation.

The Company is subject to regulation by federal, state, and local regulatory authorities and is exposed to public policy decisions that may negatively impact the Company's earnings. In particular, the Company is subject to regulation by the FERC, the NERC, the EPA, the IURC, the PUCO, the DOT, including PHMSA, the Department of Energy (DOE), the Occupational Safety and Health Administration (OSHA), and the Department of Homeland Security

(DHS). These authorities regulate many aspects of its generation, transmission and distribution operations, including construction and maintenance of facilities, operations, and safety. In addition, the IURC, the PUCO, and the FERC approve its utility-related debt and equity issuances, regulate the rates that the Company can charge customers, the rate of return the Company is authorized to earn, and its ability to timely recover gas and fuel costs and investments in infrastructure. Further, there are consumer advocates and other parties that may intervene in regulatory proceedings and affect regulatory outcomes.

Trends Toward Stricter Standards

With the historical trend toward stricter standards, greater regulation, more extensive permit requirements, and an increase in the number and types of assets operated that are subject to regulation, the Company's investment in infrastructure and the associated operating costs have increased and may increase in the future.

Pipeline Safety Considerations

The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe, efficient, and reliable manner. The Company's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and improvement. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law on January 3, 2012 and on March 18, 2016 PHMSA published a notice of proposed rulemaking on the safety of gas transmission and gathering lines. The rule, expected to be finalized in 2019, 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. In December 2016, PHMSA issued interim final rules related to integrity management for storage operations. While some compliance costs remain uncertain, these rules result in further investment in pipeline inspections, and where necessary, additional investments in pipeline and storage infrastructure. As such, the rule results in increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution and transmission systems as evidenced by recent regulatory filings and resulting Commission Orders in Indiana and Ohio for Indiana Gas, SIGECO, and VEDO.

Environmental Considerations

The Company's utility operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state, and local laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities, including particulate matter, sulfur dioxide ($SO_2$), nitrogen oxide (NOx), mercury, and non-hazardous substances such as coal combustion residuals, among others. Environmental legislation/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, including but not limited to a risk of potentially significant remediation costs from Company's coal ash ponds and related litigation. Once taken out of service, the Company's coal ash ponds must be closed in a manner acceptable to regulatory authorities. Ash pond remediation has been the subject of civil lawsuits for electric utilities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Moreover, these compliance costs will substantially change the nature of the Company's generation fleet, as outlined in the Company’s preferred integrated resource plan (IRP) and electric generation transition plan.

Climate Change Considerations

The Company and the State of Indiana are subject to the requirements of the Clean Power Plan (CPP) rule, which requires a 32 percent reduction in carbon emissions from 2005 levels. While implementation of the rule remains uncertain due to the U.S. Supreme Court stay that was granted in February 2016 to delay the regulation while being challenged in court and a more recent proposal from the EPA which, if finalized, would result in the repeal of the CPP, regulations as written in the final rule may substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plans and natural gas distribution business. In addition to regulatory risk, the Company may be subject to climate change lawsuits which could result in substantial penalties or damages. Moreover, evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels may have substantial impacts on the Company's electric generation and natural gas distribution businesses.

Evolving Physical Security and Cybersecurity Standards and Considerations
The frequency, size and variety of physical security and cybersecurity threats against companies with critical infrastructure continues to grow, as do the evolving frameworks, standards and regulations intended to keep pace with and address these threats. There continues to be a marked increase in interest from both federal and state regulatory agencies related to physical security and cybersecurity in general, and specifically in critical infrastructure sectors, including the electric and natural gas

12

sectors. The Company has dedicated internal and third party physical security and cybersecurity teams and maintains vigilance with regard to the communication and assessment of physical security and cybersecurity risks and the measures employed to protect information technology assets, critical infrastructure, the Company and its customers from these threats. Physical security and cybersecurity threats, however, constantly evolve in attempts to identify and capitalize on any weakness or unprotected areas. If these measures were to fail or if a breach were to occur, it could result in impairment or loss of critical functions, operating reliability, customer, or other confidential information. The ultimate effects, which are difficult to quantify with any certainty, are partially limited through insurance.

Increasing regulation and infrastructure replacement programs could affect the Company's utility rates charged to customers, its costs, and its profitability.

Any additional expenses or capital incurred by the Company, as it relates to complying with increasing regulation and other infrastructure replacement activities are expected to be recovered from customers in its service territories through increased rates. Increased rates have an impact on the economic health of the communities served. New regulations could also negatively impact industries in the Company's service territories.

The Company's utilities' ability to obtain rate increases and to maintain current authorized rates of return depends in part on continued interpretation of laws within the current regulatory framework. There can be no assurance the Company will be able to obtain rate increases, or rate supplements, or earn currently authorized rates of return. Indiana and Ohio have passed laws allowing utilities to recover a significant amount of the costs of complying with federal mandates or other infrastructure replacement expenditures, and in Ohio, other capital investments outside of a base rate proceeding. However, these activities may have a short-term adverse impact on the Company's cash flow and financial condition.

In addition, failure to comply with new or existing laws and regulations may result in fines, penalties, or injunctive measures and may not be recoverable from customers and could result in a material adverse effect on the Company's financial condition and results of operations.

The Company's energy delivery operations are subject to various risks.

A variety of hazards and operations risks, such as leaks, accidental explosions, and mechanical problems, are inherent in the Company’s gas and electric distribution and transmission activities. If such events occur, they could cause substantial financial losses and result in injury to or loss of human life, significant damage to property, environmental pollution, and impairment of operations. The location of pipelines, storage facilities, and the electric grid near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. These activities may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines, or penalties or be resolved on unfavorable terms. In accordance with customary industry practices, the Company maintains insurance against a significant portion, but not all, of these risks and losses. To the extent the occurrence of any of these events is not fully covered by insurance, it could adversely affect the Company’s financial condition and results of operations.

The Company's power supply operations are subject to various risks.

The Company’s electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, and increased purchase power costs. Such operational risks can arise from circumstances such as facility shutdowns due to equipment failure or operator error; interruption of fuel supply or increased prices of fuel as contracts expire; disruptions in the delivery of electricity; inability to comply with regulatory or permit requirements; labor disputes; and natural disasters. Further, the Company's coal supply is purchased largely from a single, unrelated party and, although the coal supply is under long-term contract, the loss of this supplier could impact operations.

Executing the Company's electric generation transition plan is subject to various risks.

The Company’s electric generation transition plan, discussed further herein, introduces the need for regulatory authority in order to provide timely recovery of new capital investments, as well as costs of retiring the current generation fleet, including

13

decommissioning costs, costs of removal, and any remaining unrecovered costs of retired assets. Given the significance of the plan, there is inherent risk associated with the construction of new generation, including the ability to procure resources needed to build at a reasonable cost, scarcity of resources and labor, ability to appropriately estimate costs of new generation, and the effects of potential construction delays and cost overruns. As long as the plan is prudently implemented, such risks, if they materialize, would be expected to be favorably addressed through the regulatory process. Additionally, operating risks associated with the generation transition plan may arise such as workforce retention, development and training, and the ability to meet capacity requirements.

The Company participates in the MISO.

The Company is a member of the MISO, which serves the electric 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. As a result of such control, the Company’s continued ability to import power, when necessary, and export power to the wholesale market has been, and may continue to be, impacted.

The need to expend capital for improvements to the regional electric transmission system, both to the Company’s facilities as well as to those facilities of adjacent utilities, over the next several years could be significant. The Company timely recovers its investment in certain new electric transmission projects that benefit the MISO infrastructure at a FERC approved rate of return.

Also, the MISO allocates operating costs and the cost of multi-value projects throughout the region to its participating utilities such as the Company’s regulated electric utility, and such costs are significant. Adjustments to these operating costs, including adjustments that result from participants entering or leaving the MISO, could cause increases or decreases to customer bills. The Company timely recovers its portion of MISO operating expenses as tracked costs.

Volatility in the wholesale price of natural gas, coal, and electricity could reduce earnings and working capital.

The Company has limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal, and purchased power for the benefit of retail customers due to current state regulations, which, subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. However, significant volatility in the price of natural gas, coal, or purchased power may cause existing customers to conserve or motivate them to switch to alternate sources of energy as well as cause new home developers, builders, and new customers to select alternative sources of energy. Decreases in volumes sold could reduce earnings. The decrease would be more significant in the absence of constructive regulatory orders, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs. A decline in new customers could impede growth in future earnings. In addition, during periods when commodity prices are higher than historical levels, working capital costs could increase due to higher carrying costs of inventories and cost recovery mechanisms, and customers may have trouble paying higher bills leading to increased bad debt expenses. Additionally, significant oil price fluctuations and the ability to continue shale gas drilling may impact the price of natural gas and purchased power.

Increased conservation efforts and technology advances, which result in improved energy efficiency or the development of alternative energy sources, may result in reduced demand for the Company’s energy products and services.

The trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and air conditioners and other heating and cooling devices as well as lighting, may reduce the demand for energy products. Prices for natural gas are subject to fluctuations in response to changes in supply and other market conditions. During periods of high energy commodity costs, the Company's prices generally increase, which may lead to customer conservation. Federal and state regulation may require mandatory conservation measures, which would reduce the demand for energy products. Certain federal or state regulation may also impose restrictions on building construction and design in efforts to increase conservation which may reduce demand for natural gas and electricity. In addition, the Company's customers, especially large commercial and industrial customers, may choose to employ various technological advances to develop alternative energy sources, such as the construction and development of wind power, solar technology, or electric cogeneration facilities. Increased conservation efforts and the utilization of technological advances to increase energy efficiency or to develop alternate energy sources could lead to a reduction in demand for the Company’s energy products and services, which could have an adverse effect on its revenues and overall results of operations. Similar to many states, Indiana has permitted small customers to engage in net metering for several years. In 2017, the Indiana Legislature passed a bill that provided for the phase out of subsidies being provided to those customers. The Company has experienced some growth in these applications, but the overall level of net metering on its system remains relatively low.

Emerging technologies may create disruption to utility services.

New and emerging technology may enable new approaches or choices for capacity and energy services that pressure or even disrupt how utilities provide services. Commercial technologies that successfully advance “electrifying” aspects of the economy such as transportation or space heating could negatively impact the demand for the Company’s natural gas delivery. The Company may be unable to quickly adapt to rapid change resulting from artificial intelligence, blockchain, Internet of Things (IoT) and other advanced technologies that may result in a reduction in demand for utility services or disruptive changes for how customers select their energy sources. The Company’s inclusion of fossil fuels in its portfolio may be viewed by some customers and capital markets as reason to select other energy options which new technology may enable.

The Company is exposed to physical and financial risks related to the uncertainty of climate change.

A changing climate creates uncertainty and could result in broad changes, both physical and financial in nature, to the Company’s service territories. These impacts could include, but are not limited to, population shifts; changes in the level of annual rainfall; changes in the overall average temperature; and changes to the frequency and severity of weather events such as thunderstorms, wind, tornadoes, and ice storms that can damage infrastructure. Such changes could impact the Company in a number of ways including the number and type of customers in the Company’s service territories; an increase to the cost of providing service; an increase in the amount of service interruptions; impacts to the Company's workforce; and an increase in the likelihood of capital expenditures to replace damaged infrastructure.

To the extent climate change impacts a region’s economic health, it may also impact the Company’s revenues, costs, and capital structure and thus the need for changes to rates charged to regulated customers. Rate changes themselves can impact the economic health of the communities served and may in turn adversely affect the Company’s operating results. Customers' energy needs vary with weather conditions. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require additional generating resources, transmission, and other infrastructure to serve increased load. Decreased energy use may require the Company to retire current infrastructure that is no longer needed.

In Note 11 of the Company’s Consolidated Financial Statements included in Item 8, the Company discusses the upcoming 2018 sustainability report of the Company's parent, which discusses in greater detail the Company's climate change and carbon strategy.

From time to time, the Company is subject to material litigation and regulatory proceedings.

From time to time, the Company may be subject to material litigation and regulatory proceedings, including matters involving compliance with federal and state laws, regulations or other matters. There can be no assurance that the outcome of these matters will not have a material adverse effect on the Company’s business, prospects, corporate reputation, results of operations, or financial condition.

The investment performance of pension plan holdings sponsored by the Company's parent and other factors impacting pension plan costs could impact the Company’s liquidity and results of operations.

The costs associated with retirement plans sponsored by the Company's parent, are dependent on a number of factors, such as the rates of return on plan assets; discount rates; the level of interest rates used to measure funding levels; changes in actuarial assumptions including assumed mortality; future government regulations; changes in plan design, and contributions. In addition, the Company could be required to provide for significant funding of these defined benefit pension plans. Such cash funding obligations could have a material impact on liquidity by reducing cash flows for other purposes and could negatively affect results of operations.

Catastrophic events, such as terrorist attacks, acts of civil unrest, and acts of God, may adversely affect the Company’s facilities and operations and corporate reputation.

Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks or similar occurrences could adversely affect the Company’s facilities, operations, corporate reputation, financial condition and results of operations. Either a direct act against Company-owned generating facilities or transmission and distribution infrastructure or an act against the infrastructure of neighboring utilities or interstate pipelines that are used by the Company to transport power and natural gas could result in the Company being unable to deliver natural gas or electricity for a prolonged period. In the event of a severe disruption resulting from such events, the Company has contingency plans and employs crisis management to respond and recover operations. Despite these measures, if such an occurrence were to occur, results of operations and financial condition could be materially adversely affected.

Cyber attacks or similar occurrences may adversely affect the Company's facilities, operations, corporate reputation, financial condition and results of operations.

The Company relies on information technology networks, telecommunications, and systems to, among other things, 1) operate its generating facilities; 2) engage in asset management and customer service activities; 3) process, transmit and store sensitive electronic information including intellectual property, proprietary business information and that of the Company’s suppliers and business partners, personally identifiable information of customers and employees, and data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities, and 4) process financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal, and tax requirements. Despite the Company’s security measures, any information technology system may be vulnerable to attacks by hackers or breached due to malfeasance, employee error, sabotage, or other disruptions. Security breaches, extended outage or general disruption of this information technology infrastructure could lead to system disruptions, business interruption, generating facility shutdowns or unauthorized disclosure of confidential information. In particular, any data loss or information security lapses resulting in the compromise of personal information or the improper use or disclosure of sensitive or classified information could result in claims, remediation costs, regulatory sanctions against the Company, loss of current and future contracts, and serious harm to the Company's reputation. While the Company has implemented policies, procedures, protective technologies, and controls to prevent and detect these activities, not all disruptions and misconduct may be prevented. In the event of a severe infrastructure system disruption or generating facility shutdown resulting from such events, the Company has contingency plans and employs crisis management to respond and recover operations. Despite these measures, if such an attack or security breach were to occur, results of operations and financial condition could be materially adversely affected. The ultimate effects, which are difficult to quantify with any certainty, are partially limited through insurance.

Workforce risks could affect the Company's financial results.

The Company is subject to various workforce risks, including but not limited to, the risk that it will be unable to 1) attract and retain qualified and diverse personnel; 2) effectively transfer the knowledge and expertise of an aging workforce to new personnel as those workers retire; 3) react to a pandemic illness; 4) manage the migration to more defined contribution employee benefit packages; and 5) be unable to reach collective bargaining arrangements with the unions that represent certain of its workers, which could result in work stoppages.

The Company's ability to effectively manage its third party contractors, agents, and business partners could have a significant impact on the Company's business and reputation.

The Company relies on third party contractors, agents, and business partners to perform some of the services provided to its customers, as well as assist with the monitoring of physical security and cybersecurity functions. Any misconduct by these third parties, or the Company’s inability to properly manage them, could adversely impact the provision of services to customers and the quality of services provided. Misconduct could include fraud or other improper activities, such as falsifying records and violations of laws. Other examples could include the failure to comply with the Company’s policies and procedures or with government procurement regulations, regulations regarding the use and safeguarding of classified or other protected information, legislation regarding the pricing of labor and other costs in government contracts, laws and regulations relating to environmental, health or safety matters, lobbying or similar activities, and any other applicable laws or regulations. Any data loss or information security lapses resulting in the compromise of personal information or the improper use or disclosure of sensitive or classified information could result in claims, remediation costs, regulatory sanctions against the Company, loss of current and future contracts, and serious harm to its reputation. Although the Company has implemented policies, procedures, and controls to prevent and detect these activities, these precautions may not prevent all misconduct, and as a result, the Company could face unknown risks or losses. The Company's failure to comply with applicable laws or regulations or misconduct by any of its contractors, agents, or business partners could damage its reputation and subject it to fines and penalties, restitution or other damages, loss of current and future customer contracts and suspension or debarment from contracting with federal, state or local government agencies, any of which would adversely affect the business and future results.

The Company may not have adequate insurance coverage for all potential liabilities.

Natural risks, as well as other hazards associated with the Company’s operations, can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The Company maintains an amount of insurance protection management believes is appropriate, but there can be no assurance that the amount of insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which the Company may be subject. A claim for which the Company is not adequately insured could materially harm the Company’s financial condition. Further, due to the cyclical nature of the insurance markets, management cannot provide assurance that insurance coverage will continue to be available on terms similar to those presently in place.

The performance of the Company's parent and its nonutility businesses may impact the Company.

Execution of Vectren’s nonutility business strategies, specifically Vectren Infrastructure Services Corporation (VISCO), is subject to a number of risks.

VISCO is wholly owned by the Company's parent and provides underground pipeline construction and repair services for customers including the Company. Risks specific to VISCO's strategies include, but are not limited to, success in bidding contracts; variations in the volume of contract work; unanticipated cost increases in completion of the contracted work; increases to funding requirements associated with multiemployer pension plans; the ability to attract and retain qualified employees; ability to obtain materials and equipment required to perform services from suppliers and manufacturers.

The nonutility infrastructure services business supports the Company's utilities pursuant to infrastructure service contracts. In most instances, the ability to maintain these service contracts depends upon regulatory discretion and affiliate guidelines approved by the regulators, and there can be no assurance it will be able to obtain future service contracts, or that existing arrangements will not be revisited.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

### Gas Utility Services

Indiana Gas owns and operates five active gas storage fields located in Indiana covering 61,124 acres of land with an estimated ready delivery from storage capability of 6.79 BCF of gas with maximum peak day delivery capabilities of 164,000 MCF per day. Indiana Gas also owns and operates three liquefied petroleum (propane) air-gas manufacturing plants located in Indiana with the ability to store 1.5 million gallons of propane and manufacture for delivery of 33,000 MCF of manufactured gas per day. In addition to its company owned storage and propane capabilities, Indiana Gas has 15.1 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 230,000 MMBTU per day. Indiana Gas' gas delivery system includes approximately 13,200 miles of distribution and transmission mains, all of which are in Indiana except for pipeline facilities extending from points in northern Kentucky to points in southern Indiana so that gas may be transported to Indiana and sold or transported by Indiana Gas to customers in Indiana.

SIGECO owns and operates three active underground gas storage fields located in Indiana covering 6,100 acres of land with an estimated ready delivery from storage capability of 7.03 BCF of gas with maximum peak day delivery capabilities of 109,000 MCF per day. In addition to its company owned storage delivery capabilities, SIGECO has 0.4 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 17,000 MMBTU per day. SIGECO's gas delivery system includes 3,300 miles of distribution and transmission mains, all of which are located in Indiana.

VEDO has 7.6 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 200,000 MMBTU per day. The Company has released its Ohio storage service to those retail gas marketers supplying VEDO with natural gas, and those suppliers are responsible for the demand charges. VEDO's gas delivery system includes 5,600 miles of distribution and transmission mains, all of which are located in Ohio.

### Electric Utility Services

SIGECO's installed generating capacity as of December 31, 2017, was rated at 1,248 MW. SIGECO's coal-fired generating facilities are the A.B. Brown Generating Station (AB Brown) with two units totaling 490 MW of combined capacity, located in Posey County, approximately eight miles east of Mt. Vernon, Indiana; the F.B. Culley Generating Station (Culley) with two units totaling 360 MW of combined capacity; and Warrick Unit 4 (Warrick) with 150 MW of capacity. Both the Culley and Warrick Stations are located in Warrick County near Yankeetown, Indiana. SIGECO's gas-fired turbine peaking units are: two 80 MW gas turbines (Brown Unit 3 and Brown Unit 4) located at AB Brown; one Broadway Avenue Gas Turbine located in Evansville, Indiana with a capacity of 65 MW; and two Northeast Gas Turbines located northeast of Evansville in Vanderburgh County, Indiana with a combined capacity of 20 MW. The Brown Unit 3 and Broadway Avenue Unit 2 turbines are also equipped to burn oil. Total capacity of SIGECO's five gas turbines is 245 MW, and these units are generally used only for reserve, peaking, or emergency purposes. SIGECO also has a landfill gas electric generation project in Pike County, Indiana with a total generation capability of 3 MW.

SIGECO's transmission system consists of 1,028 circuit miles of 345kV, 138kV and 69kV lines. The transmission system also includes 34 substations with an installed capacity of 4,900 megavolt amperes (Mva). The electric distribution system includes 4,543 circuit miles of lower voltage overhead lines and 462 trench miles of conduit containing 2,405 circuit miles of underground distribution cable. The distribution system also includes 85 distribution substations with an installed capacity of 2,100 Mva and 54,919 distribution transformers with an installed capacity of 2,440 Mva.

SIGECO owns utility property outside of Indiana approximating 24 miles of 138kV and 345kV electric transmission lines, which are included in the 1,028 circuit miles discussed above. These assets are located in Kentucky and interconnect with Louisville Gas and Electric Company's transmission system at Cloverport, Kentucky and with Big Rivers Electric Cooperative at Sebree, Kentucky.

Property Serving as Collateral

SIGECO's properties are subject to the lien of the First Mortgage Indenture dated as of April 1, 1932, between SIGECO and Bankers Trust Company, as Trustee, and Deutsche Bank, as successor Trustee, as supplemented by various supplemental indentures.

## ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate and regulatory matters. The consolidated financial statements are included in “Item 8 Financial Statements and Supplementary Data.”

## ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

ITEM 5. MARKET FOR COMPANY'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock Market Price

All of the outstanding shares of the Company's common stock are owned by the Company's parent. The Company's common stock is not traded. There are no outstanding options or warrants to purchase the Company's common equity or securities convertible into the Company's common equity. Additionally, the Company has no plans to publicly offer its common equity securities.

Dividends Paid to Parent

In the first quarter of 2018, the Company paid a $32.0 million dividend to its parent company.

During 2017, the Company paid quarterly dividends to its parent company totaling $30.6 million, $31.1 million, $30.8 million, and $30.8 million, respectively.

During 2016, the Company paid dividends of $29.0 million to its parent company in each quarter.

Dividends on shares of common stock are payable at the discretion of the Board of Directors out of legally available funds. Future payments of dividends, and the amounts of these dividends, will depend on the Company’s financial condition, results of operations, capital requirements, and other factors.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data is derived from the Company’s audited consolidated financial statements and should be read in conjunction with those financial statements and notes thereto contained in this Form 10-K.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| (In millions) | 2017 | 2016 | 2015 | 2014 | 2013 |
| Operating Data: | | | | | |
| Operating revenues | $1,382.6 | $1,377.8 | $1,394.5 | $1,569.7 | $1,429.6 |
| Operating income | 278.5 | 316.5 | 296.6 | 281.4 | 281.6 |
| Net income | 175.8 | 173.6 | 160.9 | 148.4 | 141.8 |
| Balance Sheet Data: | | | | | |
| Total assets | $5,497.8 | $5,040.9 | $4,592.7 | $4,409.3 | $4,127.1 |
| Long-term debt - net of current maturities & debt subject to tender | 1,479.5 | 1,331.0 | 1,379.2 | 1,154.8 | 1,248.9 |
| Common shareholder's equity | 1,722.8 | 1,624.0 | 1,535.2 | 1,478.5 | 1,432.8 |

As further discussed in Note 5 of the Consolidated Financial Statements included in Item 8 herein, net income in 2017 includes a $23.2 million net tax benefit associated with the impact of the federal corporate income tax rate reduction on the revaluation of the company's non rate-regulated deferred income tax balance as of December 31, 2017. Also reflected in net income is a non-recurring charge of $23.2 million, after tax, or $35.7 million in operating income for the non-recurring multi-year contribution to the Vectren Foundation in 2017.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

The Company generates revenue primarily from the delivery of natural gas and electric service to its customers. It's primary source of cash flow results from the collection of customer bills and payment for goods and services procured for the delivery of gas and electric services. The Company segregates its utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment.

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and notes thereto.

Executive Summary of Consolidated Results of Operations

During 2017, the Company earned $175.8 million, compared to $173.6 million in 2016 and $160.9 million in 2015. Results in 2017 compared to 2016 reflect increased earnings from the returns on continued investment in the gas infrastructure investment programs in both Indiana and Ohio. Results also reflect the expected decrease in usage of a large electric customer that completed its transition to a co-generation facility and lower electric margins as both heating and cooling degree days in 2017 were lower than in 2016. Results in 2016 compared to 2015 reflect increased earnings from the returns on the gas infrastructure replacement programs in Indiana and Ohio gas infrastructure investment programs and increases in large customer usage.

Use of Non-GAAP Performance Measures and Per Share Measures

Results Excluding Non-recurring Activity
This discussion and analysis contains non-GAAP financial measures that exclude the results related to the revaluation of deferred income taxes as of December 31, 2017 as a result of the Tax Cuts and Jobs Act ("TCJA") that was signed into law on December 22, 2017, and a 2017 expense related to a non-recurring multi-year contribution to the Vectren Foundation, a 501(c)(3) charitable organization, affiliated with but separate from the Company.

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

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

The following table reconciles net income and certain components of the financial statements from the GAAP measure to the non-GAAP measure for non-recurring activity in 2017.

| | Twelve Months Ended December 31, 2017 | | | |
|---|---|---|---|---|
| (In millions) | GAAP Measure | Deferred Tax Revaluation (Gain) / Loss | Other Operating Charge | Non-GAAP Measure |
| Net Income | $175.8 | $ (23.2) | $ 23.2 | $ 175.8 |
| Gas Utility Services | $115.5 | $ (27.3) | $ — | $ 88.2 |
| Electric Utility Services | $75.2 | $ — | $ — | $ 75.2 |
| Other Utility Operations | $(14.9) | $ 4.1 | $ 23.2 | $ 12.4 |

| | | | | |
|---|---|---|---|---|
| Other Operating Expense | $370.4 | $ — | $ (35.7 ) | $ 334.7 |
| Income Tax Expense | $60.7 | $ 23.2 | $ 12.5 | $ 96.4 |

21

Non-recurring Activity

Impact of Tax Reform on Income Tax Expense

As discussed in Note 5 in the Company's Consolidated Financial Statements included in Item 8, on December 22, 2017, comprehensive federal tax reform was enacted, referred to as the Tax Cuts and Jobs Act ("TCJA").

As a result of the TCJA, results reflect a net tax benefit of $23.2 million for the period ending December 31, 2017. This benefit is associated with the impact of the federal corporate income tax rate reduction on the Company's deferred tax balances relating to assets of the Gas Utility Services segment that are not reflected in customer rates, such as goodwill associated with past acquisitions.

Non-recurring Other Operating

Reflected in the consolidated financial statements within Other Operating Expense is a non-recurring multi-year contribution to the Vectren Foundation, a 501(c)(3) charitable organization, totaling $35.7 million, which is reflected in the Other Utility Operations segment.

Gas utility services

The gas utility services segment earned $115.5 million during the year ended December 31, 2017, compared to $76.1 million in 2016 and $64.4 million in 2015. Excluding the tax benefit from the revaluation of deferred income taxes related to acquisition goodwill not included in customer rates for the Ohio operations of $27.3 million, gas utility segment earnings were $88.2 million in 2017. The improved results in the periods presented reflect increased returns on the Indiana and Ohio infrastructure replacement programs and large customer margins. In 2016, these increases were somewhat offset by lower late fee revenue resulting from lower natural gas prices.

Electric utility services

The electric utility services segment earned $75.2 million during 2017, compared to $84.7 million in 2016 and $82.6 million in 2015. Results in 2017 reflect the expected decrease in large customer margin as a customer completed its transition to a co-generation facility, resulting in lower usage of approximately 610 GWh in 2017 compared to 2016. Electric results, which are not protected by weather normalizing mechanisms, reflect a $3.3 million decrease related to weather in 2017 compared to 2016. Results in 2016 compared to 2015 reflect a favorable impact of weather on retail electric margin, which management estimates the after tax impact to be approximately $1.8 million.

Other utility operations

In 2017, the loss from other utility operations was $14.9 million, compared to earnings of $12.8 million in 2016 and $13.9 million in 2015. Excluding the $27.3 million after-tax impact of the expense associated with the multi-year contribution to the Vectren Foundation as funded by VUHI and the related revaluation of deferred taxes, earnings from other utility operations in 2017 were $12.4 million. The higher earnings in 2015 were driven primarily by a lower effective income tax rate from increased research and development tax credits for certain qualifying information technology assets.

The Regulatory Environment

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

SIGECO and Indiana Gas). The retail gas operations of VEDO are subject to regulation by the PUCO.

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 as the Company's utilities have implemented conservation programs. In the Company's two Indiana natural gas service territories, normal temperature adjustment (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. The Ohio natural gas service territory has a straight fixed variable rate design for its residential customers. This rate design, which was fully implemented in February 2010, mitigates approximately 90 percent of the Ohio service territory's weather risk and risk of decreasing consumption specific to its small customer classes.

In all natural gas service territories, the commissions have authorized bare steel and cast iron replacement programs. In Indiana, 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. Legislation was passed in 2011 in Ohio that supports the investment in other capital projects, allowing the utility to defer the impacts of these investments until its next base rate case. The Company has received approval to implement these mechanisms in both states.

In 2017, SIGECO's electric service territory started recovering certain costs of significant 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 Indiana customers are two of the Company's most significant operating expenses. Rates charged to natural gas customers in Indiana contain a gas cost adjustment clause (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 fuel adjustment clause (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. Since April 2010, the Company has not been the supplier of natural gas in its Ohio territory.

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.

In Indiana, 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.

In Ohio, expenses such as uncollectible accounts expense, costs associated with exiting the merchant function, and costs associated with the infrastructure replacement program and other gas distribution capital expenditures are subject to recovery outside of base rates.

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

Base Rate Orders
SIGECO'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. Indiana Gas received an order and implemented rates in February 2008, and VEDO received an order in January 2009, with implementation in February 2009. The orders authorize a return on equity ranging from 10.15 percent to 10.40 percent. The authorized returns reflect the impact of rate design strategies that have been authorized by these state commissions.

See the Rate and Regulatory Matters section of this discussion and analysis for more specific information on significant proceedings involving the Company's utilities over the last three years.

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 these 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 for expenses that are subject to volatility. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas Utility Margin
Gas utility margin and throughput by customer type follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2017 | 2016 | 2015 |
| Gas utility revenues | $812.7 | $771.7 | $792.6 |
| Cost of gas sold | 271.5 | 266.7 | 305.4 |
| Total gas utility margin | $541.2 | $505.0 | $487.2 |
| Margin attributed to: | | | |
| Residential & commercial customers | $412.3 | $385.9 | $360.8 |
| Industrial customers | 73.9 | 67.1 | 61.4 |
| Other | 8.4 | 7.4 | 9.3 |
| Regulatory expense recovery mechanisms | 46.6 | 44.6 | 55.7 |
| Total gas utility margin | $541.2 | $505.0 | $487.2 |
| Sold & transported volumes in MMDth attributed to: | | | |
| Residential & commercial customers | 97.1 | 97.2 | 104.9 |
| Industrial customers | 122.2 | 127.0 | 125.3 |
| Total sold & transported volumes | 219.3 | 224.2 | 230.2 |

Gas utility margins were $541.2 million for the year ended December 31, 2017, and compared to 2016, increased $36.2 million. Gas margin was favorably impacted by increased returns on infrastructure replacement programs in Indiana and Ohio of $25.4 million, increases in large customer margin of $4.9 million, and increases associated with small customer count growth of $3.0 million. With rate designs that substantially limit the impact of weather on small customer margin, the warmer than normal weather in the first quarter of 2017 decreased sold and transported volumes, but only had a slight unfavorable impact on small customer margin compared to 2016. Heating degree days were 90 percent of normal in Ohio and 80 percent of normal in Indiana in 2017, compared to 93 percent of normal in Ohio and 84 percent of normal in Indiana in 2016.

Gas utility margins were $505.0 million for the year ended December 31, 2016, and compared to 2015, increased $17.8 million, or $28.2 million excluding regulatory expense recovery mechanisms. Gas margin was favorably impacted by increased returns on increased infrastructure replacement programs of $25.9, increases in large customer margin of $3.0 million, and increases associated with small customer count growth of $2.7 million. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 93 percent of normal in Ohio and 84 percent of normal in Indiana during 2016, compared to 95 percent of normal in Ohio and 88 percent of normal in Indiana during 2015, had only a slight unfavorable impact on small customer margin. However, warmer weather did decrease sold and transported volumes which contributed $11.1 million lower regulatory expense recovery margin and a corresponding decrease in operating expenses. Results in 2016 also reflect lower miscellaneous margin largely driven by a decrease in late fee revenue as a result of lower gas prices.

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 millions) | 2017 | 2016 | 2015 |
| Electric utility revenues | $569.6 | $605.8 | $601.6 |
| Cost of fuel & purchased power | 171.8 | 183.6 | 187.5 |
| Total electric utility margin | $397.8 | $422.2 | $414.1 |
| Margin attributed to: | | | |
| Residential & commercial customers | $254.9 | $261.2 | $258.6 |
| Industrial customers | 96.9 | 112.1 | 109.7 |
| Other | 5.6 | 5.8 | 4.5 |
| Regulatory expense recovery mechanisms | 9.6 | 13.7 | 9.6 |
| Subtotal: retail | $367.0 | $392.8 | $382.4 |
| Wholesale power & transmission system margin | 30.8 | 29.4 | 31.7 |
| Total electric utility margin | $397.8 | $422.2 | $414.1 |
| Electric volumes sold in GWh attributed to: | | | |
| Residential & commercial customers | 2,638.8 | 2,729.0 | 2,714.4 |
| Industrial customers | 2,096.5 | 2,722.3 | 2,721.5 |
| Other customers | 22.3 | 22.9 | 22.2 |
| Total retail volumes | 4,757.6 | 5,474.2 | 5,458.1 |
| Wholesale | 463.2 | 136.1 | 337.8 |
| Total volumes sold | 5,220.8 | 5,610.3 | 5,795.9 |

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 in 2017 compared to 84 percent of normal in 2016 and cooling degree days were 111 percent of normal in 2017 compared to 125 percent of normal in 2016. Margin from regulatory expense recovery mechanism decreased $4.1 million in 2017.

Electric retail utility margins were $392.8 million for the year ended December 31, 2016 and, compared to 2015, increased by $10.4 million. Electric margin reflects a $3.0 million increase from weather in small customer margin as cooling degree days were 125 percent of normal in 2016 compared to 111 percent of normal in 2015. As energy conservation initiatives continue, the Company's lost revenue recovery mechanism related to electric conservation programs contributed increased margin of $2.4 million compared to the prior year, however was offset by a decrease in small customer usage of $1.2 million. Results also reflect an increase in large customer usage of $2.2 million largely driven by timing of customer plant maintenance resulting in lower customer throughput in 2015. Margin from regulatory expense recovery mechanisms increased $4.1 million as operating expenses associated with the electric conservation programs increased.

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 millions) | 2017 | 2016 | 2015 |
| MISO Transmission system margin | $25.5 | $25.1 | $25.5 |
| MISO Off-system margin | 5.3 | 4.3 | 6.2 |
| Total wholesale margin | $30.8 | $29.4 | $31.7 |

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 and $25.5 million in 2015. 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 and $6.2 million in 2015. 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.

Operating Expenses

Other Operating

For the year ended December 31, 2017, Other operating expenses were $370.4 million, and compared to 2016, increased $36.8 million primarily related to the commitment to fund the Vectren Foundation for a multi-year period in an amount totaling $35.7 million. Excluding pass through costs, which decreased $3.1 million, and the $35.7 million funding for the Vectren Foundation, operating expenses increased $4.2 million primarily from higher performance-based compensation expense driven by an increase in the Company's stock price.

For the year ended December 31, 2016, Other operating expenses were $333.6 million, and compared to 2015, decreased $5.5 million. Excluding pass through costs, which accounted for $4.5 million of the decrease in operating expenses in 2016, other operating expenses decreased $1.0 million compared to 2015.

Depreciation & Amortization

For the year ended December 31, 2017, Depreciation and amortization expense was $234.5 million, compared to $219.1 million in 2016 and $208.8 million in 2015. Results in the periods presented reflect increased utility plant investments placed into service primarily related to gas infrastructure programs in Indiana and Ohio.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $2.4 million in 2017 compared to 2016 and increased $1.2 million in 2016 compared to 2015. The decrease in 2017 was primarily related to property taxes. Fluctuations in the periods presented are also driven by fluctuations in revenues and related revenue taxes.

Other Income-Net

Other income-net reflects income of $30.6 million in 2017, compared to $26.3 million in 2016 and $18.7 million in 2015. Results are primarily driven by increased allowance for funds used during construction (AFUDC) of approximately $5.1 million in 2017 compared to 2016, and $4.2 million in 2016 compared to 2015. The increased AFUDC in the periods presented is driven by increased capital expenditures related to gas utility infrastructure replacement investments.

Income Taxes

For the year ended December 31, 2017, federal and state income taxes were $60.7 million, compared to $99.5 million in 2016 and $88.1 million in 2015. The decrease in tax expense in 2017 compared to 2016 is due primarily to the tax benefit from the revaluation of deferred income taxes related non rate-regulated balances in an amount totaling $23.2 million as a result of the TCJA enacted on December 22, 2017, and lower income before taxes as a result of the multi-year funding of the Vectren Foundation. The increase in income taxes in 2016 compared to 2015 is primarily due to increased income in 2016 and research and development tax credits recognized in 2015.

Gas Rate and Regulatory Matters

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

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

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred for future recovery in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

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

Indiana Recovery and Deferral Mechanisms

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

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

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

Subsequent to the March 2016 Order, the Company has received additional Orders approving plan investments. 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 $482 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 $995 million through 2020. The plan increase, totaling $105 million since inception, is for additional investments related to pipeline safety and compliance requirements under Senate Bill 251.

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 $15 million of operating expenses and $17 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. The Company does not have company-owned storage operations in Ohio.

At December 31, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $78.0 million and $51.1 million, respectively.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $321.1 million as of December 31, 2017, of which $261.1 million has been approved for recovery under the DRR through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $31.2 million and $24.4 million at December 31, 2017 and December 31, 2016, respectively. In August 2017, the Company received approval to adjust the DRR rates, effective December 31, 2017, for recovery of costs incurred through December 31, 2016.

The PUCO has also issued Orders approving the Company's filings under House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. At December 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $66.1 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of December 31, 2017, the Company's deferrals have not reached this bill impact cap. On May 1, 2017, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Vectren Ohio Gas Rate Case

On February 21, 2018, the Company submitted a pre-filing notice with the PUCO indicating it plans to request an increase in its base rate charges for VEDO’s distribution business in its 17 county service area in west-central Ohio. The filing is necessary to recover the costs of capital investments made over the past ten years, much of which has been deferred as part of the Company’s capital expenditure program under House Bill 95. Also in the filing, the Company seeks approval for the continuation of the DRR mechanism. The Company will file the case-in-chief at the end of March 2018, and expects an order by early 2019.

Pipeline and Hazardous Materials Safety Administration (PHMSA)

In March 2016, PHMSA published a notice of proposed rulemaking (NOPR) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a 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 in Indiana and eligible for deferral under House Bill 95 in Ohio.

Electric Rate and 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. The parties agreed in the settlement that the Company would make its first semi-annual filing on August 1, 2017, with additional time allotted subsequent to the plan case order for intervening parties to review the filing and to address any changes to the settlement agreement.

On August 1, 2017, the Company filed with the IURC its initial request for approval of the revenue requirement associated with 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.

SIGECO Electric Demand Side Management (DSM) Program Filing
On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, 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, 2016, and 2015, the Company recognized electric utility revenue of $11.6 million, $11.1 million, and $10.1 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 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.

Environmental and Sustainability Matters

The Company's parent initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report. Since that time, the Company and its parent continue 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

33

regulations, are directly overseen by Vectren's Board of Directors through its 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 the Company’s current sustainability report, at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

In furtherance of the Company’s commitment to a sustainable business model, and as detailed further below, the Company is transitioning its electric generation portfolio from nearly total reliance on baseload coal to a fully diversified and balanced portfolio of fuels that will provide long term electric supply needs in a safe and reliable manner while dramatically lowering emissions of carbon and the carbon intensity of its electric generating fleet. If authorized by the Commission, by 2024, the Company plans to construct a new natural gas combined cycle 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, 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 ($SO_2$), nitrogen oxide ($NO_x$), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August, the EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. While the state program development and EPA

reconsideration move forward, the existing CCR compliance obligations remain in effect.

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

Throughout 2016 and 2017, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $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 ELG setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELG will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence where operations continue, within the 2018-2023 time frame. The ELG work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company’s 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 17 in the Company’s Consolidated Financial Statements included in Item 8.

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.

Air Quality

Ozone NAAQS

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

One Hour SO2 NAAQS

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

Climate Change and Carbon Strategy

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

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

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;

- Provisions for enhanced use of renewable energy sources as a supplement to baseload generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for research and development and investment in advanced clean coal technology; and
- A strategy supporting alternative energy technologies and biofuels and continued increase in the domestic supply of natural gas and oil to reduce dependence on foreign oil.

Current Initiatives to Increase Conservation & Reduce Emissions

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

- Since 2005 and through 2017, the Company has achieved a reduction in emissions of $CO_2$ of 30 percent (on a tonnage basis) through the retirement of F.B. Culley Unit 1, expiration of municipal contracts, electric conservation, the addition of renewable generation, and the installation of more efficient dense pack turbine technology. The three year average emission reduction for the period 2015 to 2017 is 35 percent from 2005 levels.
- The Company’s parent's mission statement and purpose is focused on corporate sustainability and the need to help customers conserve and manage energy costs. The annual sustainability report continues to receive Core level certification by the Global Reporting Initiative and demonstrates the commitment to sustainability and transparency in operations. The current sustainability report can be found at www.vectren.com/sustainability;
- Implementing home and business energy efficiency initiatives in the Company’s Indiana and Ohio gas utility service territories such as offering rebates on high efficiency furnaces, programmable thermostats, and insulation and duct sealing;
- Implementing home and business energy efficiency initiatives in the electric service territory such as rebate programs on central air conditioning units, LED lighting, home weatherization and energy audits;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Further reducing the Company’s carbon footprint by building a more sustainable vehicle fleet with lower overall fuel consumption;
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets; and
- Working with the Company’s gas supply administrator in Indiana to maximize the amount of natural gas delivered to our customers that has been sourced from members of The Environmental Partnership, an organization that includes many of the major oil and gas producers in the U.S and who have committed to continuously improving the industry’s environmental performance;

Clean Power Plan

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.7 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's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of December 31, 2017 and 2016, approximately $2.5 million and $2.9 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance

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 Consolidated Balance Sheets, Consolidated 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. Most of the Company's parent's share-based awards are settled via cash payments, most of which are funded by the Company, and were therefore not impacted by this standard. The Company's parent's adoption of this standard did not have a material impact on the financial statements.

Presentation of Net Periodic Pension and Postretirement Benefit Costs
In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension and postretirement benefit costs. This ASU is effective for annual periods beginning after December 15, 2017, and relevant interim periods. This ASU requires the Company to report the service cost component incurred by the Company's parent 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.

Critical Accounting Policies

Management is required to make judgments, assumptions, and estimates that affect the amounts reported in the consolidated financial statements and the related disclosures that conform to accounting principles generally accepted in the United States. The footnotes to the consolidated financial statements describe the significant accounting policies and methods used in their preparation. Certain estimates are subjective and use variables that require judgment. These include the estimates to perform goodwill and other asset impairments tests and to allocate support services, assets, and its pension and postretirement benefit obligations from the Company's parent. The Company makes other estimates related to the effects of regulation that are critical to the Company’s financial results but that are less likely to be impacted by near term changes. Other estimates that significantly affect the Company’s results, but are not necessarily critical to operations, include depreciating utility and nonutility plant, valuing asset retirement obligations, and estimating uncollectible accounts, unbilled revenues, and deferred income taxes, among others. Actual results could differ from these estimates.

Impairment Review of Investments and Long-Lived Assets

Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review primarily involves consideration of the likelihood of abandonment and a potentially related disallowance as well as the actions of regulators in the jurisdictions in which the Company operates.

Goodwill

The Company performs an annual impairment analysis of its goodwill, most of which resides in the Gas Utility Services operating segment, at the beginning of each year, and more frequently if events or circumstances indicate that an impairment loss may have been incurred. Impairment tests are performed at the reporting unit level. The Company has determined its Gas Utility Services operating segment to be the level at which impairment is tested as its reporting units are similar. An impairment test requires fair value to be estimated. The Company used a discounted cash flow model and other market based information to estimate the fair value of its Gas Utility Services operating segment, and that estimated fair value was compared to its carrying amount, including goodwill. The estimated fair value has been substantially in excess of the carrying amount in each of the last three years and therefore resulted in no impairment.

Estimating fair value using a discounted cash flow model is subjective and requires judgment in applying a discount rate, growth assumptions, company expense allocations, and longevity of cash flows. A 100 basis point increase in the discount rate utilized to calculate the Gas Utility Services segment’s fair value also would have resulted in no impairment charge.

Intercompany Allocations

Support Services
The Company's parent provides corporate, general, and administrative services to the Company and allocates costs to the Company. These costs have been 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. Management believes that the allocation methodology is reasonable and approximates the costs that would have been incurred had the Company secured those services on a stand-alone basis. The allocation methodology is not subject to near term changes.

Pension and Other Postretirement Obligations

The Company's parent satisfies the funding requirements for its funded pension plans and benefit payments for its unfunded other postretirement plan and supplemental executive retirement plan 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 commitment. The pension plans are closed to new participants.

The Company's parent allocates retirement plan and other postretirement benefit plan periodic cost calculated pursuant to US GAAP to its subsidiaries, which is also how the Company’s rate regulated utilities recover retirement plan periodic costs through base rates. Periodic 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.

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 US GAAP are allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. 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's subsidiaries.

The Company's parent estimates the expected return on plan assets, discount rate, rate of compensation increase, and future health care costs, among other inputs, and obtains actuarial estimates to assess the future potential liability and funding requirements of pension and postretirement plans. The Company's parent used the following weighted average assumptions to develop 2017 periodic benefit cost: a discount rate of approximately 4.07 percent, an expected return on plan assets of 7.0 percent, a rate of compensation increase of 3.5 percent, and an inflation assumption of 2.5 percent.

Due to lower interest rates, the discount rate is approximately 25 basis points lower from the assumption used in 2016. Also due to a continued low interest rate environment, the long-term rate of return assumption was lowered to 7.0 percent in 2017 from 7.5 percent in 2016.

Inflation rates and rate of compensation increase remained the same from 2016 to 2017.

To estimate 2018 costs, the following weighted average assumptions were used: a discount rate of approximately 3.61 percent; an expected return on plan assets of 7.00 percent; a rate of compensation increase of 3.50 percent; and an inflation assumption of 2.50 percent. The discount rate was based on benchmark interest rates and the expected rate of return on plan assets was determined using a building block approach.

Future changes in health care costs, work force demographics, interest rates, asset values or plan changes could significantly affect the estimated cost of these future benefits. Vectren’s management currently estimates a pension and postretirement cost of approximately $6.7 million in 2018, compared to actuals of $8.2 million in 2017, $5.6 million in 2016, and $9.9 million in 2015. Approximately $6.6 million of the cost estimated for 2018 will be allocated to the Company.

Vectren’s management estimates that a 50 basis point increase in the discount rate used to estimate retirement costs generally decreases periodic benefit cost by approximately $1.6 million.

Regulation

At each reporting date, the Company reviews current regulatory trends in the markets in which it operates. This review involves judgment and is critical in assessing the recoverability of regulatory assets as well as the ability to continue to account for its activities based on the criteria set forth in FASB guidance related to accounting for the effects of certain types of regulation. Based on the Company’s current review, it believes its regulatory assets are probable of recovery. If all or part of the Company's operations cease to meet the criteria, a write-off of related regulatory assets and liabilities could be required. In addition, the Company would be required to determine any impairment to the carrying value of its utility plant and other regulated assets and liabilities. In the unlikely event of a change in the current regulatory environment, such write-offs and impairment charges could be significant.

Financial Condition

The Company funds the short-term and long-term financing needs of its utility subsidiary operations. The Company's parent does not guarantee the Company's debt. Outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The guarantees are full and unconditional and joint and several,

41

and the Company has no subsidiaries other than the subsidiary guarantors.  Information about the subsidiary guarantors as a group is included in Note 15 to the consolidated financial statements.  Long-term debt and short-term obligations outstanding at December 31, 2017 approximated $1.2 billion and $180 million, respectively.  Additionally, prior to the Company's formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations.  SIGECO will also occasionally issue new tax exempt debt to fund qualifying pollution control capital expenditures.  Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at December 31, 2017 was $385 million.

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

The credit ratings of the senior unsecured debt of the Company and Indiana Gas, at December 31, 2017, were A-/A2 as rated by Standard and Poor's and Moody’s, respectively.  The credit ratings on SIGECO's secured debt were A/Aa3.  The Company's commercial paper had a credit rating of A-2/P-1.  The current outlook of both Moody’s and Standard and Poor’s is stable.  A security rating is not a recommendation to buy, sell, or hold securities.  The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating.  Standard and Poor’s and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

The Company’s consolidated equity capitalization objective is 50-60 percent of long-term capitalization.  This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company’s operations.  The Company’s equity component was 52 percent and 54 percent of long-term capitalization at December 31, 2017 and 2016, respectively.  Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders’ equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions.  Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent.  As of December 31, 2017, the Company was in compliance with all debt covenants.

Available Liquidity

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

The Company routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. This authority allows for the flexibility for each utility to issue debt and equity securities to third parties or to issue debt and equity securities to the Company and thus receive some of the proceeds from various Company issuances to third parties on the same terms as those obtained by the Company. The majority of the long-term debt needs of the utilities are expected to be met through these debt issuances, some or all of which are then reloaned to the individual utilities. On July 21, 2017, an Order for long-term financing authority of $70 million of long-term debt and $65 million of equity financing was received from the PUCO for VEDO and expires in June 2018. On February 22, 2017, orders for long-term financing authority of $160 million and $200 million of long-term debt, and $120 million and $180 million of equity financing, were received from the IURC for SIGECO and Indiana Gas, respectively. These orders expire in March 2019.

Short-Term Borrowings
On July 14, 2017, the Company closed on a renegotiated credit agreement with existing lenders. This credit agreement matures on July 14, 2022 and replaced a bank credit agreement that had an original maturity date of October 19, 2019. The Company's new credit facility totals $400 million with a $10 million swing line sublimit and $20 million letter of credit sublimit. The credit

agreement commitment was increased by $50 million as compared to the prior credit agreement. The Company's credit agreement is jointly and severally guaranteed by its wholly owned subsidiaries Indiana Gas, SIGECO, and VEDO and is a backup facility for its commercial paper program. The commercial paper program is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis. As reduced by borrowings outstanding at December 31, 2017, approximately $220 million was available.

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

| (In millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| As of Year End | | | |
| Balance Outstanding | $179.5 | $194.4 | $14.5 |
| Weighted Average Interest Rate | 1.92 % | 1.05 % | 0.55 % |
| Annual Average | | | |
| Balance Outstanding | $172.4 | $59.8 | $53.8 |
| Weighted Average Interest Rate | 1.30 % | 0.71 % | 0.38 % |
| Maximum Month End Balance Outstanding | $238.7 | $194.4 | $121.5 |

Proceeds from Stock Plans and Additional Capital Contributions
The Company's parent may periodically reallocate capital or issue new common shares to satisfy dividend reinvestment plan and other employee benefit plan requirements and contribute those proceeds to the Company. In 2017 and 2016, additional capital of $40.0 million and $25.0 million, respectively, was received from the nonutility operations of the Company's parent to partially fund the Company's capital expenditure program. In addition, issues of new common shares for the Company's parents' dividend reinvestment plan in 2017, 2016, and 2015 added additional liquidity to the Company of $6.3 million, $6.3 million and $6.2 million, respectively.

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

Potential Uses of Liquidity

Planned Capital Expenditures
During 2017, capital expenditures approximated $550 million, compared to $500 million in 2016 and $400 million in 2015.  Planned capital expenditures, including contractual purchase commitments, for the five-year period 2018 – 2022 are expected to total approximately $590 million in 2018, $595 million in 2019, $560 million in 2020, $735 million in 2021, and $920 million in 2022. Expenditures are expected to be higher beginning in 2021 due to the construction of the combined cycle generating facility. This plan contains the best estimate of the resources required for known regulatory compliance and the generation transition plan; however, many environmental and pipeline safety standards are subject to change in the near term. Such changes could materially impact planned capital expenditures.

Pension and Postretirement Funding Obligations

As of December 31, 2017, assets related to the Company's parent's qualified pension plans were approximately 92 percent for accounting purposes and 116 percent of the target liability for ERISA purposes. The Company's parent expects to make contributions totaling $3.5 million to its qualified pension plans in 2018, a majority of which will be funded by the Company.

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2017:

| | Total | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|---|
| Long-term debt (1) | $1,579.5 | $100.0 | $— | $100.0 | $55.0 | $4.6 | $ 1,319.9 |
| Short-term debt | 179.5 | 179.5 | — | — | — | — | — |
| Long-term debt interest commitments | 1,124.5 | 71.1 | 67.7 | 63.3 | 61.4 | 59.0 | 802.0 |
| Plant purchase commitments | 43.0 | 18.0 | 6.6 | 5.2 | 5.2 | 4.0 | 4.0 |
| Operating leases | 5.1 | 1.1 | 0.9 | 0.6 | 0.6 | 0.5 | 1.4 |
| Total (2) | $2,931.6 | $369.7 | $75.2 | $169.1 | $122.2 | $68.1 | $ 2,127.3 |

(1) The debt due in 2018 is comprised of debt issued by Utility Holdings

(2) The Company has other long-term liabilities that total approximately $212 million. This amount is comprised of the following: allocated portions of Vectren's deferred compensation and share-based compensation $46 million, asset retirement obligations $107 million, allocated portions of Vectren's postretirement obligations totaling $47 million, investment tax credits $1 million, environmental remediation $3 million, and other obligations totaling $8 million. Based on the nature of these items their expected settlement dates cannot be estimated.

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

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $446.8 million in 2017, compared to $397.4 million in 2016 and $492.9 million in 2015. The $49.4 million increase in operating cash flow in 2017 compared to 2016 is due to increased collections from customers and a reduction in pension plan contributions as the Company's parent elected not to fund the pension plans in 2017. The increase was partially offset by the elimination of bonus depreciation in the fourth quarter of 2017 as a result of the TCJA.

The $95.5 million decrease in operating cash flow in 2016 compared to 2015 is driven primarily by changes in certain working capital accounts that reflect weather impacts, including reduced collections from customers and increased unrecovered fuel and natural gas costs. In addition, tax payments to the Company's parent increased in 2016 compared to 2015.

Financing Cash Flow

Net cash flow from financing activities for the years ended December 31, 2017 and 2016 was an inflow of $106.6 million and $82.1 million, respectively, and an outflow of $104.8 million for the year ended December 31, 2015. Financing activity reflects the Company’s utilization of the long-term capital markets in the current low interest rate environment. In the current year, the Company raised $198.5 million, net of issuance costs, in the private placement capital market to fund capital expenditures. During 2015, financing activities reflect the issuance of debt for the purposes of refinancing maturing debt and paying down short term borrowings. The Company’s operating cash flow funded 66 percent of capital expenditures and dividends in 2017, 65 percent of capital expenditures and dividends in 2016, and 97 percent of capital expenditures and dividends in 2015. Recently completed long-term financing transactions are more fully described below.

Investing Cash Flow

Cash flow required for investing activities was $553.0 million in 2017, $476.3 million in 2016, and $401.2 million in 2015.  The primary use of cash in all years reflects expenditures for utility plant. The increase in capital expenditures over the years presented is attributable to greater expenditures for gas infrastructure improvement projects and environmental compliance.

Utility Holdings Long-Term Debt Issuance
On July 14, 2017, Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors agreed to purchase the following tranches of notes: (i) $100 million of 3.26 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 Indiana Gas, SIGECO, and VEDO, wholly owned subsidiaries of Utility Holdings.

The Series A note proceeds were received on August 28, 2017 and the Series B proceeds were received on November 29, 2017.

SIGECO Variable Rate Tax-Exempt Bonds
On September 14, 2017, the Company, through SIGECO, executed a Bond Purchase and Covenants Agreement (Purchase and Covenants Agreement) providing SIGECO 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, SIGECO also extended the mandatory tender date of its variable rate 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025 (the original tender date was September 24, 2019).

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

SIGECO Bond Retirement
On June 1, 2016, a $13 million SIGECO 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 Company’s commercial paper program.

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.

Forward-Looking Information

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

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

46

- 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

The Company's parent has a risk management committee that consists of senior management as well as financial and operational management. The committee is actively involved in identifying risks as well as reviewing and authorizing risk mitigation strategies.

Commodity Price Risk

Regulated Operations

The Company has limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal and purchased power for the benefit of retail customers due to current state regulations, which subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. Constructive regulatory orders, such as those authorizing lost margin recovery, other innovative rate designs, and recovery of unaccounted for gas and other gas related expenses, also mitigate the effect gas costs may have on the Company's financial condition. Although the Company's regulated operations are exposed to limited commodity price risk, natural gas and coal prices have other effects on working capital requirements, interest costs, and some level of price-sensitivity in volumes sold or delivered. Indiana Gas and SIGECO hedge up to 50 percent of annual natural gas purchases for each Company utilizing a variety of terms with forward purchase arrangements up to 5 years and physical fixed-price purchases up to 10 years in duration. Indiana Gas also utilizes financial products, including call options. Such option contracts are generally short-term in nature and are insignificant in terms of value and volume at December 31, 2017 and 2016.

Wholesale Power Marketing

The Company's wholesale power marketing activities undertake strategies to optimize electric generating capacity beyond that needed for native load. In recent years, the primary strategy involves the sale of generation into the MISO Day Ahead and Real-time markets. The Company accounts for any energy contracts that are derivatives at fair value with the offset marked to market through earnings. No derivative positions were outstanding on December 31, 2017 and 2016.

For retail sales of electricity, the Company receives the majority of its NOx and $SO_2$ allowances at zero cost through an allocation process. Based on arrangements with regulators, wholesale operations can purchase allowances from retail operations at current market values, the value of which is distributed back to retail customers through a MISO cost recovery tracking mechanism. Wholesale operations are therefore at risk for the cost of allowances, which for the recent past have been volatile. The Company manages this risk by purchasing allowances from retail operations as needed and occasionally from other third parties in advance of usage.

Other Operations

Other commodity-related operations are exposed to commodity price risk associated with gasoline/diesel through third party suppliers. Occasionally, the Company will hedge a portion of such requirements using financial instruments and using physically settled forward purchase contracts. However, during the years presented, such utilization has not been significant.

Interest Rate Risk

The Company is exposed to interest rate risk associated with its borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on interest expense. As of December 31, 2017, debt subject to interest rate volatility was approximately 15 percent. To further manage this exposure, the Company may also use

48

derivative financial instruments and currently has outstanding hedging instruments that mitigate interest rate volatility beginning in 2020.

Market risk is estimated as the potential impact resulting from fluctuations in interest rates on adjustable rate borrowing arrangements exposed to short-term interest rate volatility. During 2017 and 2016, the weighted average combined borrowings under these arrangements approximated $228 million and $101 million, respectively. At December 31, 2017, combined borrowings under these arrangements were $270 million. As of December 31, 2016, combined borrowings under these arrangements were $236 million. Based upon average borrowing rates under these facilities during the years ended December 31, 2017 and 2016, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by approximately $2.3 million in 2017 and $1.0 million in 2016.

Other Risks

By using financial instruments and physically settled fixed price forward contracts to manage risk, the Company creates exposure to counter-party credit risk and market risk. The Company manages exposure to counter-party credit risk by entering into contracts with companies that can be reasonably expected to fully perform under the terms of the contract. Counter-party credit risk is monitored regularly and positions are adjusted appropriately to manage risk. Further, tools such as netting arrangements and requests for collateral are also used to manage credit risk. Market risk is the adverse effect on the value of a financial instrument that results from a change in commodity prices or interest rates. The Company attempts to manage exposure to market risk associated with commodity contracts and interest rates by establishing parameters and monitoring those parameters that limit the types and degree of market risk that may be undertaken.

The Company’s customer receivables associated with utility operations are primarily derived from residential, commercial, and industrial customers located in Indiana and west-central Ohio. The Company manages credit risk associated with its receivables by continually reviewing creditworthiness and requests cash deposits or refunds cash deposits based on that review. Credit risk associated with certain investments is also managed by a review of creditworthiness and receipt of collateral. In addition, credit risk for the Company's utilities is mitigated by regulatory orders that allow recovery of all uncollectible accounts expense in Ohio and the gas cost portion of uncollectible accounts expense in Indiana based on historical experience.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT’S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Vectren Utility Holdings, Inc.’s management is responsible for establishing and maintaining adequate internal control over financial reporting. Those control procedures underlie the preparation of the consolidated balance sheets, statements of income, cash flows, and common shareholder's equity, and related footnotes contained herein.

These consolidated financial statements were prepared in conformity with accounting principles generally accepted in the United States and follow accounting policies and principles applicable to regulated public utilities. The integrity and objectivity of these consolidated financial statements, including required estimates and judgments, is the responsibility of management.

These consolidated financial statements are also subject to an evaluation of internal control over financial reporting conducted under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer. Based on that evaluation, conducted under the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, the Company concluded that its internal control over financial reporting was effective as of December 31, 2017. Management certified this in its Sarbanes Oxley Section 302 certifications, which are filed as exhibits to this 2017 Form 10-K.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Board of Directors of Vectren Utility Holdings, Inc.:

### Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vectren Utility Holdings, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, common shareholder’s equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

### Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 8, 2018

We have served as the Company’s auditor since 2002.

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

| | At December 31, | |
|---|---|---|
| | 2017 | 2016 |
| ASSETS | | |
| Current Assets | | |
| Cash & cash equivalents | $9.8 | $9.4 |
| Accounts receivable - less reserves of $3.9 & $4.1, respectively | 109.5 | 102.6 |
| Accrued unbilled revenues | 123.7 | 112.0 |
| Inventories | 117.5 | 119.0 |
| Recoverable fuel & natural gas costs | 19.2 | 29.9 |
| Prepayments & other current assets | 32.7 | 38.6 |
| Total current assets | 412.4 | 411.5 |
| Utility Plant | | |
| Original cost | 7,015.4 | 6,545.4 |
| Less: accumulated depreciation & amortization | 2,738.7 | 2,562.5 |
| Net utility plant | 4,276.7 | 3,982.9 |
| Investments in unconsolidated affiliates | 0.2 | 0.2 |
| Other investments | 26.7 | 21.3 |
| Nonutility plant - net | 198.6 | 164.8 |
| Goodwill | 205.0 | 205.0 |
| Regulatory assets | 314.0 | 206.2 |
| Other assets | 64.2 | 49.0 |
| TOTAL ASSETS | $5,497.8 | $5,040.9 |

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

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

| | At December 31, | |
|---|---|---|
| | 2017 | 2016 |
| LIABILITIES & SHAREHOLDER'S EQUITY | | |
| Current Liabilities | | |
| Accounts payable | $221.8 | $205.4 |
| Payables to other Vectren companies | 33.3 | 25.4 |
| Accrued liabilities | 154.0 | 140.1 |
| Short-term borrowings | 179.5 | 194.4 |
| Current maturities of long-term debt | 100.0 | 49.1 |
| Total current liabilities | 688.6 | 614.4 |
| Long-Term Debt - Net of Current Maturities | 1,479.5 | 1,331.0 |
| | | |
| Deferred Credits & Other Liabilities | | |
| Deferred income taxes | 457.5 | 854.5 |
| Regulatory liabilities | 937.2 | 453.7 |
| Deferred credits & other liabilities | 212.2 | 163.3 |
| Total deferred credits & other liabilities | 1,606.9 | 1,471.5 |
| Commitments & Contingencies (Notes 8-11) | | |
| Common Shareholder's Equity | | |
| Common stock (no par value) | 877.5 | 831.2 |
| Retained earnings | 845.3 | 792.8 |
| Total common shareholder's equity | 1,722.8 | 1,624.0 |
| TOTAL LIABILITIES & SHAREHOLDER'S EQUITY | $5,497.8 | $5,040.9 |

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

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| OPERATING REVENUES | | | |
| Gas utility | $812.7 | $771.7 | $792.6 |
| Electric utility | 569.6 | 605.8 | 601.6 |
| Other | 0.3 | 0.3 | 0.3 |
| Total operating revenues | 1,382.6 | 1,377.8 | 1,394.5 |
| OPERATING EXPENSES | | | |
| Cost of gas sold | 271.5 | 266.7 | 305.4 |
| Cost of fuel & purchased power | 171.8 | 183.6 | 187.5 |
| Other operating | 370.4 | 333.6 | 339.1 |
| Depreciation & amortization | 234.5 | 219.1 | 208.8 |
| Taxes other than income taxes | 55.9 | 58.3 | 57.1 |
| Total operating expenses | 1,104.1 | 1,061.3 | 1,097.9 |
| OPERATING INCOME | 278.5 | 316.5 | 296.6 |
| Other income - net | 30.6 | 26.3 | 18.7 |
| Interest expense | 72.6 | 69.7 | 66.3 |
| INCOME BEFORE INCOME TAXES | 236.5 | 273.1 | 249.0 |
| Income taxes | 60.7 | 99.5 | 88.1 |
| NET INCOME | $175.8 | $173.6 | $160.9 |

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

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | $175.8 | $173.6 | $160.9 |
| Adjustments to reconcile net income to cash from operating activities: | | | |
| Depreciation & amortization | 234.5 | 219.1 | 208.8 |
| Deferred income taxes & investment tax credits | 45.9 | 96.7 | 85.8 |
| Provision for uncollectible accounts | 5.7 | 6.6 | 6.9 |
| Expense portion of pension & postretirement benefit cost | 3.5 | 4.0 | 4.8 |
| Other non-cash items - net | 2.0 | 3.5 | 7.0 |
| Changes in working capital accounts: | | | |
| Accounts receivable, including to Vectren companies & accrued unbilled revenues | (27.0) | (48.8) | 50.5 |
| Inventories | 1.5 | 6.3 | (12.1) |
| Recoverable/refundable fuel & natural gas costs | 10.7 | (37.8) | 15.2 |
| Prepayments & other current assets | 5.1 | 5.0 | 30.0 |
| Accounts payable, including to Vectren companies & affiliated companies | 26.2 | 23.9 | (15.2) |
| Accrued Liabilities | 13.9 | 18.7 | 0.7 |
| Cash to fund pension and postretirement plans | — | (15.0) | (19.6) |
| Changes in noncurrent assets | (66.0) | (46.5) | (23.7) |
| Changes in noncurrent liabilities | 15.0 | (11.9) | (7.1) |
| Net cash from operating activities | 446.8 | 397.4 | 492.9 |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Proceeds from: | | | |
| Long-term debt, net of issuance costs | 198.5 | — | 236.3 |
| Additional capital contribution | 46.3 | 31.3 | 6.2 |
| Requirements for: | | | |
| Dividends to parent | (123.3) | (116.1) | (110.4) |
| Retirement of long-term debt | — | (13.0) | (95.0) |
| Net change in short-term borrowings | (14.9) | 179.9 | (141.9) |
| Net cash from financing activities | 106.6 | 82.1 | (104.8) |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Proceeds from other investing activities | 2.7 | 15.3 | 3.9 |
| Requirements for: | | | |
| Capital expenditures, excluding AFUDC equity | (554.2) | (496.6) | (399.2) |
| Other costs | (2.4) | — | — |
| Changes in restricted cash | 0.9 | 5.0 | (5.9) |
| Net cash from investing activities | (553.0) | (476.3) | (401.2) |
| Net change in cash & cash equivalents | 0.4 | 3.2 | (13.1) |
| Cash & cash equivalents at beginning of period | 9.4 | 6.2 | 19.3 |
| Cash & cash equivalents at end of period | $9.8 | $9.4 | $6.2 |

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

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

| | Common Stock | Retained Earnings | Total |
|---|---|---|---|
| Balance at January 1, 2015 | $ 793.7 | $ 684.8 | $ 1,478.5 |
| Net income | | 160.9 | 160.9 |
| Common stock: | | | |
| Additional capital contribution | 6.2 | | 6.2 |
| Dividends | | (110.4) | (110.4) |
| Balance at December 31, 2015 | 799.9 | 735.3 | 1,535.2 |
| Net income | | 173.6 | 173.6 |
| Common stock: | | | |
| Additional capital contribution | 31.3 | | 31.3 |
| Dividends | | (116.1) | (116.1) |
| Balance at December 31, 2016 | 831.2 | 792.8 | 1,624.0 |
| Net income | | 175.8 | 175.8 |
| Common stock: | | | |
| Additional capital contribution | 46.3 | | 46.3 |
| Dividends | | (123.3) | (123.3) |
| Balance at December 31, 2017 | $ 877.5 | $ 845.3 | $ 1,722.8 |

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

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

## 1. Organization and Nature of Operations

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

Indiana Gas provides energy delivery services to approximately 592,400 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 145,200 electric customers and approximately 111,500 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 318,100 natural gas customers located near Dayton in west-central Ohio.

## 2. Summary of Significant Accounting Policies

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

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

### Subsequent Events Review
Management performs a review of subsequent events for any events occurring after the balance sheet date but prior to the date the financial statements are issued.

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

### Allowance for Uncollectible Accounts
The Company maintains allowances for uncollectible accounts for estimated losses resulting from the inability of its customers to make required payments. The Company estimates the allowance for uncollectible accounts based on a variety of factors including the length of time receivables are past due, the financial health of its customers, unusual

macroeconomic conditions, and historical experience. If the financial condition of its customers deteriorates or other circumstances occur that result in an impairment of customers' ability to make payments, the Company records additional allowances as needed.

Inventories

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

Property, Plant & Equipment

Both the Company’s Utility Plant and Nonutility Plant 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

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

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

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

Nonutility Plant & Related Depreciation

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

Impairment Reviews

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

Goodwill

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

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

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

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

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

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

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

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

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

When the Company engages in energy contracts and financial contracts that are derivatives and are not subject to the NPNS or other exclusions, such contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and when the contracts are expected to be settled. Contracts and any associated collateral with counter-parties subject to master netting arrangements are presented net in the Consolidated Balance Sheets. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to regulatory accounting treatment. The offset to contracts affected by regulatory accounting treatment, which 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. Substantially all revenue sources are subject to unbilled accruals.

MISO Transactions

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

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

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

Excise & Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $29.1 million in 2017, $28.3 million in 2016, and $29.4 million in 2015. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

Operating Segments

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

Fair Value Measurements

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

61

| | |
|---|---|
| Level 1 | Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets. |
| Level 2 | Inputs to the valuation methodology include<br>· quoted prices for similar assets or liabilities in active markets;<br>· quoted prices for identical or similar assets or liabilities in inactive markets;<br>· inputs other than quoted prices that are observable for the asset or liability;<br>· inputs that are derived principally from or corroborated by observable market data by correlation or other means<br>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 & Nonutility Plant

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 millions) | 2017 | | | 2016 | | |
| | Original Cost | Depreciation Rates as a Percent of Original Cost | | Original Cost | Depreciation Rates as a Percent of Original Cost | |
| Gas utility plant | $3,969.6 | 3.4 | % | $3,587.5 | 3.4 | % |
| Electric utility plant | 2,833.5 | 3.3 | % | 2,752.0 | 3.3 | % |
| Common utility plant | 59.0 | 3.2 | % | 56.3 | 3.2 | % |
| Construction work in progress | 70.7 | — | | 63.0 | — | |
| Asset retirement obligations | 82.6 | — | | 86.6 | — | |
| Total original cost | $7,015.4 | | | $6,545.4 | | |

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own a 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common. SIGECO's share of the cost of this unit at December 31, 2017, is $191.0 million with accumulated depreciation totaling $119.7 million. AGC and SIGECO share equally in the cost of operation and output of the unit. SIGECO's share of operating costs is included in Other operating expenses in the Consolidated Statements of Income.

Nonutility Plant, net of accumulated depreciation and amortization follows:

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |
| Computer hardware & software | $155.6 | $120.5 |

| | | |
|---|---|---|
| Land & buildings | 37.1 | 37.6 |
| All other | 5.9 | 6.7 |
| Nonutility plant - net | $198.6 | $164.8 |

Nonutility plant is presented net of accumulated depreciation and amortization of $285.6 million and $264.7 million as of December 31, 2017 and 2016, respectively. For the years ended December 31, 2017, 2016, and 2015, the Company capitalized interest totaling $1.2 million, $1.0 million, and $0.4 million, respectively, on nonutility plant construction projects.

4. Regulatory Assets & Liabilities

Regulatory Assets
Regulatory assets consist of the following:

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |
| Future amounts recoverable from ratepayers related to: | | |
| Net deferred income taxes | $6.2 | $(17.1 ) |
| Asset retirement obligations & other | 24.3 | — |
| | 30.5 | (17.1 ) |
| Amounts deferred for future recovery related to: | | |
| Cost recovery riders & other | 142.4 | 91.6 |
| | 142.4 | 91.6 |
| Amounts currently recovered in customer rates related to: | | |
| Indiana authorized trackers | 75.9 | 64.2 |
| Ohio authorized trackers | 28.4 | 22.2 |
| Loss on reacquired debt & hedging costs | 22.7 | 24.1 |
| Deferred coal costs | 14.1 | 21.2 |
| | 141.1 | 131.7 |
| Total regulatory assets | $314.0 | $206.2 |

Of the $141 million currently being recovered in customer rates, no amounts are earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $23 million, is 20 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 $937 million and $454 million, respectively, $477 million and $452 million of which related to cost of removal obligations, and at December 31, 2017, $459 million to deferred taxes. The deferred tax related regulatory liability is primarily the result of the $446 million 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 and Affiliates

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of the Company's parent, provides underground pipeline construction and repair services. VISCO's customers include the Company's utilities and fees incurred by the Company totaled $157.1 million in 2017, $117.8 million in 2016, and $109.5 million in 2015. The increase in 2017 is due to a large pipeline project that VISCO was awarded in a competitive process. Amounts owed to VISCO at December 31, 2017 and 2016 are included in Payables to other Vectren companies.

Support Services & Purchases

The Company's parent provides corporate and general and administrative services to the Company and allocates certain costs to the Company. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures.  Allocations are at cost.  The Company received corporate allocations totaling $64.1 million, $57.6 million, and $52.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Retirement Plans & Other Postretirement Benefits

At December 31, 2017, the Company's parent maintains three qualified defined benefit pension plans (Vectren Corporation Non-Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The pension and SERP plans are closed to new participants. The defined benefit pension plans and postretirement benefit plan, which cover the Company’s eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The Company's current and former employees comprise the vast majority of the participants and retirees covered by these plans.

The Company's parent satisfies the future funding requirements for funded plans and the payment of benefits for unfunded plans from general corporate assets and, as necessary, relies on the Company to support the funding of these obligations. However, the Company has no contractual funding obligation. In 2016, the Company contributed $15.0 million to Vectren's defined benefit pension plans. No contributions were made in 2017. The combined funded status of Vectren's defined benefit pension plans was approximately 92 percent at December 31, 2017 and December 31, 2016.

The Company's parent allocates retirement plan and other postretirement benefit plan periodic cost calculated pursuant to US GAAP to its subsidiaries, which is also how the Company’s rate regulated utilities recover retirement plan periodic costs through base rates. Periodic 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, 2016 and 2015, costs totaling $8.2 million, $6.1 million and $7.0 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 calculated pursuant to US 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 has $61.3 million, and $40.9 million, respectively, included in Other assets representing defined benefit funding by the Company that is yet to be reflected in costs. As of December 31, 2017 and 2016, the Company has $47.0 million and $12.2 million, respectively, included in Deferred credits & other liabilities representing costs related to other postretirement benefits charged to the Company that is yet to be funded to the Company's parent. The Company's labor allocation methodology is used to compute the funding of the defined benefit retirement and other postretirement plans, which is consistent with the regulatory ratemaking processes of the Company's subsidiaries.

Share-Based Incentive Plans & Deferred Compensation Plans

The Company does not have share-based compensation plans separate from the Company's parent. The Company recognizes its allocated portion of costs related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash that liability is pushed down to the Company. As of December 31, 2017 and 2016, $55.7 million and $42.3 million, respectively, is included in Accrued liabilities and Deferred credits & other liabilities and represents obligations that are yet to be funded to the Company's parent.

Income Taxes

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

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

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

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

On December 22, 2017, the United States government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act ("TCJA"). The TCJA makes broad and complex changes to the Internal Revenue Code ("IRC"), many of which are effective on January 1, 2018, including, but not limited to, (1) reducing the federal corporate income tax rate from 35 percent to 21 percent, (2) eliminating the use of bonus depreciation for regulated utilities, while permitting full expensing of qualified property for non-regulated entities, (3) eliminating the domestic production activities deduction previously allowable under Section 199 of the IRC, (4) creating a new limitation on the deductibility of interest expense for non-regulated businesses, (5) eliminating the corporate Alternative Minimum Tax ("AMT") and changing how existing AMT credits can be realized, (6) limiting the deductibility of certain executive compensation, (7) restricting the deductibility of entertainment and lobbying-related expenses, (8) requiring regulated entities to employ the average rate assumption method ("ARAM") to refund excess deferred taxes created by the rate change to their customers, and (9) changing the rules under Section 118 of the IRC regarding taxability of contributions made by government or civic groups.

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

The Company's gas and electric utilities currently recover corporate income tax expense in Commission approved rates charged to customers. The IURC and PUCO both issued orders which initiated proceedings to investigate the impact of the TCJA on utility companies and customers within each state. In addition, both Commissions have ordered each utility to establish regulatory assets and liabilities to record all estimated impacts of tax reform starting January 1, 2018. The Company is complying with both orders. In Indiana, 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 expects to initiate proceedings to effect the timely reduction in customer bills due to the lower corporate federal income tax rate in the very near term. In Ohio, in response to the PUCO's request for comments from utilities, Vectren submitted its response indicating that the issues should be address in its base rate case, for which the pre-filing notice was filed February 21, 2018.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2017 | 2016 | 2015 |
| Current: | | | |
| Federal | $10.0 | $(1.4 ) | $(1.9 ) |
| State | 4.8 | 4.2 | 4.2 |
| Total current taxes | 14.8 | 2.8 | 2.3 |
| Deferred: | | | |
| Federal | 43.9 | 93.5 | 81.7 |
| State | 2.4 | 3.7 | 4.6 |
| Total deferred taxes | 46.3 | 97.2 | 86.3 |
| Amortization of investment tax credits | (0.4 ) | (0.5 ) | (0.5 ) |
| Total income tax expense | $60.7 | $99.5 | $88.1 |

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Statutory rate | 35.0 % | 35.0 % | 35.0 % |
| State and local taxes-net of federal benefit | 2.8 | 2.6 | 2.8 |
| Deferred tax revaluation-tax law change | (9.8 ) | — | — |
| Amortization of investment tax credit | (0.2 ) | (0.2 ) | (0.2 ) |
| Domestic production deduction | (1.1 ) | (0.5 ) | (0.9 ) |
| Research and development credit | (0.3 ) | (0.8 ) | (2.0 ) |
| All other - net | (0.7 ) | 0.3 | 0.7 |
| Effective tax rate | 25.7 % | 36.4 % | 35.4 % |

Significant components of the net deferred tax liability follow:

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |
| Noncurrent deferred tax liabilities (assets): | | |
| Depreciation & cost recovery timing differences | $537.2 | $821.6 |
| Regulatory assets recoverable through future rates | 7.9 | 17.6 |
| Alternative minimum tax carryforward | (12.2 ) | (29.3 ) |
| Employee benefit obligations | (0.3 ) | 10.2 |
| U.S. federal charitable contributions carryforwards | (6.2 ) | — |
| Regulatory liabilities to be settled through future rates | (116.2 ) | (15.9 ) |
| Deferred fuel costs | 16.2 | 25.9 |
| Other – net | 31.1 | 24.4 |
| Net noncurrent deferred tax liability | $457.5 | $854.5 |

At December 31, 2017 and 2016, investment tax credits totaling $1.2 million and $1.6 million, respectively, are included in Deferred credits & other liabilities. At December 31, 2017, the Company has alternative minimum tax carryforwards of $12.2 million, which do not expire. The TCJA eliminated the alternative minimum tax after 2017. Pursuant to the TCJA, the Company will be able to recover its alternative minimum tax carryforwards created in 2017 and prior in future periods.

Uncertain Tax Positions

Unrecognized tax benefits for all periods presented were not material to the Company. The net liability on the Consolidated Balance Sheet for unrecognized tax benefits inclusive of interest and penalties totaled $1.3 million and $1.1 million, respectively, at December 31, 2017 and 2016.

The Company's parent and/or certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) 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 federal return 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's Parent and subsidiaries were 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 will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning 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

Short-Term Borrowings

On July 14, 2017, the Company closed on a renegotiated credit agreement with existing lenders. This credit agreement matures on July 14, 2022 and replaced a bank credit agreement that had an original maturity date of October 19, 2019. The Company's new credit facility totals $400 million with a $10 million swing line sublimit and $20 million letter of credit sublimit. The credit agreement commitment was increased by $50 million as compared to the prior credit agreement. The Company's credit agreement is jointly and severally guaranteed by its wholly owned subsidiaries Indiana Gas, SIGECO, and VEDO and is a backup facility for its commercial paper program. The commercial paper program is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis. As reduced by borrowings outstanding at December 31, 2017, approximately $220 million was available.

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

| (In millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Year End | | | |
| Balance Outstanding | $179.5 | $194.4 | $14.5 |
| Weighted Average Interest Rate | 1.92 % | 1.05 % | 0.55 % |
| Annual Average | | | |
| Balance Outstanding | $172.4 | $59.8 | $53.8 |
| Weighted Average Interest Rate | 1.30 % | 0.71 % | 0.38 % |
| Maximum Month End Balance Outstanding | $238.7 | $194.4 | $121.5 |

Long-Term Debt

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

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |
| Utility Holdings | | |
| Fixed Rate Senior Unsecured Notes | | |
| 2018, 5.75% | $100.0 | $100.0 |
| 2020, 6.28% | 100.0 | 100.0 |
| 2021, 4.67% | 55.0 | 55.0 |
| 2023, 3.72% | 150.0 | 150.0 |
| 2026, 5.02% | 60.0 | 60.0 |
| 2028, 3.20% | 45.0 | 45.0 |
| 2032, 3.26% | 100.0 | — |
| 2035, 6.10% | 75.0 | 75.0 |
| 2035, 3.90% | 25.0 | 25.0 |
| 2041, 5.99% | 35.0 | 35.0 |
| 2042, 5.00% | 100.0 | 100.0 |
| 2043, 4.25% | 80.0 | 80.0 |
| 2045, 4.36% | 135.0 | 135.0 |
| 2047, 3.93% | 100.0 | — |
| 2055, 4.51% | 40.0 | 40.0 |
| Total Utility Holdings | 1,200.0 | 1,000.0 |
| SIGECO | | |
| First Mortgage Bonds | | |
| 2022, 2013 Series C, current adjustable rate 1.565%, tax exempt | 4.6 | 4.6 |
| 2024, 2013 Series D, current adjustable rate 1.565%, tax exempt | 22.5 | 22.5 |
| 2025, 2014 Series B, current adjustable rate 1.565%, tax-exempt | 41.3 | 41.3 |
| 2029, 1999 Series, 6.72% | 80.0 | 80.0 |
| 2037, 2013 Series E, current adjustable rate 1.565%, tax exempt | 22.0 | 22.0 |
| 2038, 2013 Series A, 4.00%, tax exempt | 22.2 | 22.2 |
| 2043, 2013 Series B, 4.05%, tax exempt | 39.6 | 39.6 |
| 2044, 2014 Series A, 4.00%, tax exempt | 22.3 | 22.3 |
| 2055, 2015 Series Mt. Vernon, 2.375%, tax-exempt | 23.0 | 23.0 |
| 2055, 2015 Series Warrick County, 2.375%, tax-exempt | 15.2 | 15.2 |
| Total SIGECO | 292.7 | 292.7 |
| Indiana Gas | | |
| Fixed Rate Senior Unsecured Notes | | |
| 2025, Series E, 6.53% | 10.0 | 10.0 |
| 2027, Series E, 6.42% | 5.0 | 5.0 |
| 2027, Series E, 6.68% | 1.0 | 1.0 |
| 2027, Series F, 6.34% | 20.0 | 20.0 |
| 2028, Series F, 6.36% | 10.0 | 10.0 |
| 2028, Series F, 6.55% | 20.0 | 20.0 |
| 2029, Series G, 7.08% | 30.0 | 30.0 |
| Total Indiana Gas | 96.0 | 96.0 |
| Total long-term debt outstanding | 1,588.7 | 1,388.7 |
| Current maturities of long-term debt | (100.0) | (49.1) |
| Debt issuance costs | (8.6) | (7.9) |
| Unamortized debt premium & discount - net | (0.6) | (0.7) |

| | | |
|---|---|---|
| Total long-term debt-net | $ 1,479.5 | $ 1,331.0 |

Utility Holdings Long-Term Debt Issuance
On July 14, 2017, Utility Holdings entered into a private placement Note Purchase Agreement pursuant to which institutional investors agreed to purchase the following tranches of notes: (i) $100 million of 3.26 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 Indiana Gas, SIGECO, and VEDO, wholly owned subsidiaries of Utility Holdings.

The Series A note proceeds were received on August 28, 2017 and the Series B proceeds were received on November 29, 2017.

SIGECO Variable Rate Tax-Exempt Bonds

On September 14, 2017, the Company, through SIGECO, executed a Bond Purchase and Covenants Agreement (Purchase and Covenants Agreement) providing SIGECO 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, SIGECO also extended the mandatory tender date of its variable rate 2014 Series B Notes with a principal of $41.3 million and final maturity date of July 1, 2025 (the original tender date was September 24, 2019).

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

SIGECO Bond Retirement

On June 1, 2016, a $13 million SIGECO 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 Company's commercial paper program.

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 SIGECO's first mortgage bonds is 1 percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. SIGECO met the 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 Consolidated Balance Sheets. At December 31, 2017, $1.5 billion of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture. SIGECO’s gross utility plant balance subject to the Mortgage Indenture approximated $3.4 billion at December 31, 2017.

Consolidated maturities of long-term debt during the years following 2017 (in millions) are $100.0 in 2018, $100.0 in 2020, $55.0 in 2021, $4.6 in 2022, and $1,319.9 thereafter. There are no maturities of long-term debt in 2019.

Debt Guarantees
The Company's currently outstanding long-term and short-term debt is jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The Company's long-term debt and short-term debt outstanding at December 31, 2017, totaled $1.2 billion and $180 million, respectively.

Covenants
Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of December 31, 2017, the Company was in compliance with all debt covenants.

7. Common Shareholder's Equity

During the years ended December 31, 2017, 2016, and 2015, the Company has cumulatively received additional capital of $83.8 million from the Company's parent, of which $18.8 million was funded by new share issues from its dividend reinvestment plan and $65.0 million was received during 2016 and 2017 from the nonutility operations of the Company's parent to fund the Company's capital expenditure program.

8. Commitments & Contingencies

Commitments
Future minimum lease payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year during the five years following 2017 and thereafter (in millions) are $1.1 in 2018, $0.9 in 2019, $0.6 in 2020, $0.6 in 2021, $0.5 in 2022, and $1.4 thereafter. Total lease expense, for these types of commitments, (in millions) was $1.3 in 2017, $1.1 in 2016, and $0.8 in 2015.

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

Letters of Credit
The Company, from time to time, through its subsidiaries, issues letters of credit that support consolidated operations. At December 31, 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.

9. Gas Rate and Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

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

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

Indiana Senate Bill 560 (Senate Bill 560) supplements Senate Bill 251 described above, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for current recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on the investment that reflects the current capital structure and associated costs, with the exception of the rate of return on equity, which remains fixed at the rate determined in the Company's last rate case. Recoverable costs also include recovery of depreciation and other operating expenses. The remaining 20 percent of project costs are deferred for future recovery in the utility’s next general rate case, which must be filed before the expiration of the seven-year plan. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

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

Indiana Recovery and Deferral Mechanisms

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

Requests for Recovery under Indiana Regulatory Mechanisms

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

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

Subsequent to the March 2016 Order, the Company has received additional Orders approving plan investments. 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 $482 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 $995 million through 2020. The plan increase, totaling $105 million since inception, is for additional investments related to pipeline safety and compliance requirements under Senate Bill 251.

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 $15 million of operating expenses and $17 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. The Company does not have company-owned storage operations in Ohio.

At December 31, 2017 and December 31, 2016, the Company has regulatory assets related to the Plan totaling $78.0 million and $51.1 million, respectively.

Ohio Recovery and Deferral Mechanisms

The PUCO Order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines, as well as certain other infrastructure investments. This rider is updated annually for qualifying capital expenditures and allows for a return on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post-in-service carrying costs is also allowed until the related capital expenditures are included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. On February 19, 2014, the PUCO issued an Order approving a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of certain other infrastructure investments. The Order limits the resulting DRR fixed charge per month for residential and small general service customers to specific graduated levels through 2017. The capital expenditure plan is subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In the event the Company exceeds these caps, amounts in excess can be deferred for future recovery. The Order also approved the Company's commitment that the DRR can only be further extended as part of a base rate case. In total, the Company has made capital investments on projects that are now in-service under the DRR totaling $321.1 million as of December 31, 2017, of which $261.1 million has been approved for recovery under the DRR through December 31, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $31.2 million and $24.4 million at December 31, 2017 and December 31, 2016, respectively. In August 2017, the Company received approval to adjust the DRR rates, effective December 31, 2017, for recovery of costs incurred through December 31, 2016.

The PUCO has also issued Orders approving the Company's filings under House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. House Bill 95 Orders also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and small general service customer per month. At December 31, 2017 and December 31, 2016, the Company has regulatory assets totaling $66.1 million and $41.9 million, respectively, associated with the deferral of depreciation, post-in-service carrying costs, and property taxes. As of December 31, 2017, the Company's deferrals have not reached this bill impact cap. On May 1, 2017, the Company submitted its most recent annual report required under its House Bill 95 Order. This report covers the Company's capital expenditure program through calendar year 2017.

Vectren Ohio Gas Rate Case
On February 21, 2018, the Company submitted a pre-filing notice with the PUCO indicating it plans to request an increase in its base rate charges for VEDO’s distribution business in its 17 county service area in west-central Ohio. The filing is necessary to recover the costs of capital investments made over the past ten years, much of which has been deferred as part of the Company’s capital expenditure program under House Bill 95. Also in the filing, the Company seeks approval for the continuation of the DRR mechanism. The Company will file the case-in-chief at the end of March 2018, and expects an order by early 2019.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
In March 2016, PHMSA published a notice of proposed rulemaking (NOPR) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements of the 2011 Pipeline Safety Act, with a 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 in Indiana and eligible for deferral under House Bill 95 in Ohio.

10. Electric Rate and 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. The parties agreed in the settlement that the Company would make its first semi-annual filing on August 1, 2017, with additional time allotted subsequent to the plan case order for intervening parties to review the filing and to address any changes to the settlement agreement.

On August 1, 2017, the Company filed with the IURC its initial request for approval of the revenue requirement associated with 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.

SIGECO Electric Demand Side Management (DSM) Program Filing

On March 28, 2014, Indiana Senate Bill 340 was signed into law. The legislation allows for industrial customers to opt out of participating in energy efficiency programs and as a result of this legislation, 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, 2016, and 2015, the Company recognized electric utility revenue of $11.6 million, $11.1 million, and $10.1 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 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.

11. Environmental and Sustainability Matters

The Company's parent initiated a corporate sustainability program in 2012 with the publication of the initial corporate sustainability report. Since that time, the Company and its parent continue 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 Board of Directors through its 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 the Company’s current sustainability report, at www.vectren.com/sustainability, which received core level certification from the Global Reporting Initiative.

In furtherance of the Company’s commitment to a sustainable business model, and as detailed further below, the Company is transitioning its electric generation portfolio from nearly total reliance on baseload coal to a fully diversified and balanced portfolio of fuels that will provide long term electric supply needs in a safe and reliable manner while dramatically lowering emissions of carbon and the carbon intensity of its electric generating fleet. If authorized by the Commission, by 2024, the Company plans to construct a new natural gas combined cycle 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, 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 ($SO_2$), nitrogen oxide ($NO_x$), and mercury, among others. Environmental legislation and regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. Similar to the costs associated with federal mandates in the Pipeline Safety Law, Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In April 2015, the EPA finalized its Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR Rule, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed in December 2016 by Congress that would provide for enforcement of the federal program by states under approved state programs rather than citizen suits. Additionally, aspects of the CCR rule are currently being challenged by multiple parties in judicial review proceedings. In August, the EPA issued guidance to states to clarify their ability to implement the Federal CCR rule through state permit programs as allowed in the WIIN Act legislation. Alternative compliance mechanisms for groundwater, corrective action and other areas of the rule could be granted under the regulatory oversight of a state enforced program. On September 14, 2017, the EPA announced its intent to reconsider portions of the Federal CCR rule in line with the guidance issued to states. While the state program development and EPA reconsideration move forward, the existing CCR compliance obligations remain in effect.

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

Throughout 2016 and 2017, the Company has continued to refine site specific estimates and now estimates the costs to be in the range of $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 ELG setting stringent technology-based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELG will be implemented when existing water discharge permits for the plants are renewed, with compliance activities

expected to commence where operations continue, within the 2018-2023 time frame. The ELG work in tandem with the aforementioned CCR requirements, effectively prohibiting the use of less costly lined sediment basin options for disposal of coal combustion residuals, and virtually mandate conversions to dry bottom ash handling.

At the time of ELG finalization, the wastewater discharge permit for the A.B. Brown power plant had an expiration date of October 2016 and, for the F.B. Culley plant, a date of December 2016, and final renewals were issued by the Indiana

Department of Environmental Management (IDEM) in February 2017 and March 2017, respectively. As part of the permit renewals, the Company requested alternate compliance dates for ELG, which were approved by IDEM. For plants identified in the Company's 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 17 in the Company's Consolidated Financial Statements included in Item 8.

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.

Air Quality

Ozone NAAQS

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

One Hour SO2 NAAQS

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

Climate Change and Carbon Strategy

On August 3, 2015, the EPA released its final Clean Power Plan rule (CPP) which required a 32 percent reduction in carbon emissions from 2005 levels. This would result in a final emission rate goal for Indiana of 1,242 lb. $CO_2$/MWh to be achieved by 2030 and implemented through a state implementation plan. The final rule was published in the Federal Register on October 23, 2015, and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January 2016, the reviewing court denied the states' and other parties requests to stay the implementation of the CPP pending completion of judicial review. On January 26, 2016, 29 states and state agencies, including the 24 state coalition referenced above, filed a request for immediate stay of implementation of the rule with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted the stay request to delay the implementation of the regulation while being challenged in court. Oral argument was held in September 2016. The stay will remain in place while the lower court concludes its review. In March 2017, as part of the ongoing regulatory reform efforts of the Administration, the EPA filed a motion with the U.S. Court of Appeals for the District of Columbia circuit to suspend litigation pending the EPA's reconsideration of the CPP rule, which was granted on April 28, 2017. Moreover, as indicated above, in October, 2017, EPA published its proposal to repeal the CPP. Comments to the repeal proposal 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 $CO_2$ by an average of 35 percent (on a tonnage basis), and will increase that total to 60 percent at the conclusion of its generation transition plan, well above the 32 percent reduction that would be required under the CPP. While the litigation and the EPA's reconsideration of the CPP rules remains uncertain, the Company will continue to monitor regulatory activity regarding GHG emission standards that may affect its electric generating units.

Manufactured Gas Plants

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $44.2 million ($23.9 million at Indiana Gas and $20.3 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received approximately $15.7 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’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of December 31, 2017 and 2016, approximately $2.5 million and $2.9 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

12. Fair Value Measurements

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

| | At December 31, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| (In millions) | Carrying Amount | Est. Fair Value | Carrying Amount | Est. Fair Value |
| Long-term debt | $1,579.5 | $1,715.2 | $1,380.1 | $1,495.3 |
| Short-term borrowings & notes payable | 179.5 | 179.5 | 194.4 | 194.4 |
| Cash & cash equivalents | 9.8 | 9.8 | 9.4 | 9.4 |
| Natural gas purchase instrument assets (1) | 0.5 | 0.5 | — | — |
| Natural gas purchase instrument liabilities (2) | 4.5 | 4.5 | — | — |
| Interest rate swap liabilities (3) | 1.4 | 1.4 | — | — |
| Restricted cash | — | — | 0.9 | 0.9 |

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

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

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

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

The Company, through SIGECO, executed forward starting interest rate swaps during 2017 providing that on January 1, 2020, the Company will begin hedging the variability in interest rates on the 2013 Series A, B, and E Notes, 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 SIGECO to include the impact of its interest rate risk management activities, such as gains and losses arising from these swaps, in its cost of capital utilized in rate cases and other periodic filings.

13. Segment Reporting

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

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2017 | 2016 | 2015 |
| Revenues | | | |
| Gas Utility Services | $812.7 | $771.7 | $792.6 |
| Electric Utility Services | 569.6 | 605.8 | 601.6 |
| Other Operations | 45.6 | 42.2 | 40.7 |
| Eliminations | (45.3) | (41.9) | (40.4) |
| Total revenues | $1,382.6 | $1,377.8 | $1,394.5 |
| Profitability Measure - Net Income | | | |
| Gas Utility Services | $115.5 | $76.1 | $64.4 |
| Electric Utility Services | 75.2 | 84.7 | 82.6 |
| Other Operations | (14.9) | 12.8 | 13.9 |
| Total net income | $175.8 | $173.6 | $160.9 |
| Amounts Included in Profitability Measures | | | |
| Depreciation & Amortization | | | |
| Gas Utility Services | $118.9 | $108.1 | $98.6 |
| Electric Utility Services | 89.5 | 87.1 | 85.6 |
| Other Operations | 26.1 | 23.9 | 24.6 |
| Total depreciation & amortization | $234.5 | $219.1 | $208.8 |
| Interest Expense | | | |
| Gas Utility Services | $43.0 | $40.1 | $35.8 |
| Electric Utility Services | 25.8 | 27.0 | 27.8 |
| Other Operations | 3.8 | 2.6 | 2.7 |
| Total interest expense | $72.6 | $69.7 | $66.3 |
| Income Taxes | | | |
| Gas Utility Services | $25.4 | $47.1 | $40.8 |
| Electric Utility Services | 41.4 | 50.1 | 49.3 |
| Other Operations | (6.1) | 2.3 | (2.0) |
| Total income taxes | $60.7 | $99.5 | $88.1 |
| Capital Expenditures | | | |
| Gas Utility Services | $391.4 | $358.5 | $291.2 |
| Electric Utility Services | 105.3 | 106.4 | 87.6 |
| Other Operations | 60.1 | 39.0 | 25.7 |
| Non-cash costs & changes in accruals | (2.6) | (7.3) | (5.3) |
| Total capital expenditures | $554.2 | $496.6 | $399.2 |

| | At December 31, | | |
|---|---|---|---|
| (In millions) | 2017 | 2016 | 2015 |
| Assets | | | |
| Gas Utility Services | $3,457.8 | $3,091.0 | $2,706.9 |
| Electric Utility Services | 1,820.3 | 1,788.4 | 1,778.3 |
| Other Operations, net of eliminations | 219.7 | 161.5 | 107.5 |
| Total assets | $5,497.8 | $5,040.9 | $4,592.7 |

14. Additional Balance Sheet & Operational Information

Inventories consist of the following:

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |
| Gas in storage – at LIFO cost | $36.0 | $37.0 |
| Materials & supplies | 37.0 | 38.1 |
| Coal & oil for electric generation - at average cost | 43.1 | 42.6 |
| Other | 1.4 | 1.3 |
| Total inventories | $117.5 | $119.0 |

Based on the average cost of gas purchased during December, the cost of replacing inventories carried at LIFO cost is less than the carrying value at December 31, 2017 by $2.0 million. Based on the average cost of gas purchased during December, the cost of replacing inventories carried at LIFO cost exceeded carrying value at December 31, 2016 by $1.0 million.

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

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |
| Prepaid gas delivery service | $26.6 | $26.4 |
| Prepaid taxes | 2.6 | 8.0 |
| Other prepayments & current assets | 3.5 | 4.2 |
| Total prepayments & other current assets | $32.7 | $38.6 |

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

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |
| Cash surrender value of life insurance policies | $25.4 | $20.4 |
| Restricted cash & other investments | 1.3 | 0.9 |
| Total other investments | $26.7 | $21.3 |

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

| | At December 31, | |
|---|---|---|
| (In millions) | 2017 | 2016 |

| | | |
|---|---|---|
| Refunds to customers & customer deposits | $51.4 | $49.4 |
| Accrued taxes | 55.8 | 44.8 |
| Accrued interest | 17.9 | 16.4 |
| Accrued salaries & other | 28.9 | 29.5 |
| Total accrued liabilities | $154.0 | $140.1 |

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

| (In millions) | 2017 | 2016 |
|---|---|---|
| Asset retirement obligation, January 1 | $106.6 | $81.9 |
| Accretion | 4.3 | 3.8 |
| Changes in estimates, net of cash payments | (4.0) | 20.9 |
| Asset retirement obligation, December 31 | $106.9 | $106.6 |

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2017 | 2016 | 2015 |
| AFUDC - borrowed funds | $24.8 | $20.3 | $16.3 |
| AFUDC - equity funds | 2.6 | 2.2 | 2.6 |
| Nonutility plant capitalized interest | 1.2 | 1.0 | 0.4 |
| Interest income | — | 0.3 | 0.6 |
| Other income | 2.0 | 2.5 | (1.2) |
| Total other – net | $30.6 | $26.3 | $18.7 |

Supplemental Cash Flow Information:

| | Year Ended December 31, | | |
|---|---|---|---|
| (In millions) | 2017 | 2016 | 2015 |
| Cash paid (received) for: | | | |
| Interest | $71.2 | $69.6 | $66.2 |
| Income taxes | (6.1) | 6.7 | (23.1) |

As of December 31, 2017 and 2016, the Company has accruals related to utility and nonutility plant purchases totaling approximately $27.5 million and $27.4 million, respectively.

15. Subsidiary Guarantor & Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO, are guarantors of the Company's $400 million in short-term credit facilities, of which $180 million was outstanding at December 31, 2017, and the Company's $1.2 billion in unsecured senior notes outstanding at December 31, 2017. The guarantees are full and unconditional and joint and several, and the Company has no subsidiaries other than the subsidiary guarantors. However, it does have operations other than those of the subsidiary guarantors. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors, which are wholly owned, separate from the parent company's operations is required. Following are consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

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

| | Subsidiary Guarantors | Parent Company | Reclassifications and Eliminations | Consolidated |
|---|---|---|---|---|
| OPERATING REVENUES | | | | |
| Gas utility | $ 812.7 | $ — | $ — | $ 812.7 |
| Electric utility | 569.6 | — | — | 569.6 |
| Other | — | 45.6 | (45.3) | 0.3 |
| Total operating revenues | 1,382.3 | 45.6 | (45.3) | 1,382.6 |
| OPERATING EXPENSES | | | | |
| Cost of gas sold | 271.5 | — | — | 271.5 |
| Cost of fuel & purchased power | 171.8 | — | — | 171.8 |
| Other operating | 378.6 | 35.7 | (43.9) | 370.4 |
| Depreciation & amortization | 208.4 | 26.0 | 0.1 | 234.5 |
| Taxes other than income taxes | 53.8 | 2.0 | 0.1 | 55.9 |
| Total operating expenses | 1,084.1 | 63.7 | (43.7) | 1,104.1 |
| OPERATING INCOME | 298.2 | (18.1) | (1.6) | 278.5 |
| OTHER INCOME (EXPENSE) | | | | |
| Equity in earnings of consolidated companies | — | 190.7 | (190.7) | — |
| Other – net | 28.2 | 50.3 | (47.9) | 30.6 |
| Total other income (expense) | 28.2 | 241.0 | (238.6) | 30.6 |
| Interest expense | 68.8 | 53.3 | (49.5) | 72.6 |
| INCOME BEFORE INCOME TAXES | 257.6 | 169.6 | (190.7) | 236.5 |
| Income taxes | 66.9 | (6.2) | — | 60.7 |
| NET INCOME | $ 190.7 | $ 175.8 | $ (190.7) | $ 175.8 |

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

| | Subsidiary Guarantors | Parent Company | Reclassifications and Eliminations | Consolidated |
|---|---|---|---|---|
| OPERATING REVENUES | | | | |
| Gas utility | $ 771.7 | $ — | $ — | $ 771.7 |
| Electric utility | 605.8 | — | — | 605.8 |
| Other | — | 42.2 | (41.9) | 0.3 |
| Total operating revenues | 1,377.5 | 42.2 | (41.9) | 1,377.8 |
| OPERATING EXPENSES | | | | |
| Cost of gas sold | 266.7 | — | — | 266.7 |
| Cost of fuel & purchased power | 183.6 | — | — | 183.6 |
| Other operating | 374.0 | — | (40.4) | 333.6 |
| Depreciation & amortization | 195.2 | 23.8 | 0.1 | 219.1 |
| Taxes other than income taxes | 56.8 | 1.5 | — | 58.3 |
| Total operating expenses | 1,076.3 | 25.3 | (40.3) | 1,061.3 |
| OPERATING INCOME | 301.2 | 16.9 | (1.6) | 316.5 |
| OTHER INCOME (EXPENSE) | | | | |
| Equity in earnings of consolidated companies | — | 160.8 | (160.8) | — |
| Other – net | 24.0 | 48.3 | (46.0) | 26.3 |
| Total other income (expense) | 24.0 | 209.1 | (206.8) | 26.3 |
| Interest expense | 67.2 | 50.1 | (47.6) | 69.7 |
| INCOME BEFORE INCOME TAXES | 258.0 | 175.9 | (160.8) | 273.1 |
| Income taxes | 97.2 | 2.3 | — | 99.5 |
| NET INCOME | $ 160.8 | $ 173.6 | $ (160.8) | $ 173.6 |

Consolidating Statement of Income for the year ended December 31, 2015 (in millions):

| | Subsidiary Guarantors | Parent Company | Reclassifications and Eliminations | Consolidated |
|---|---|---|---|---|
| OPERATING REVENUES | | | | |
| Gas utility | $ 792.6 | $ — | $ — | $ 792.6 |
| Electric utility | 601.6 | — | — | 601.6 |
| Other | — | 40.7 | (40.4) | 0.3 |
| Total operating revenues | 1,394.2 | 40.7 | (40.4) | 1,394.5 |
| OPERATING EXPENSES | | | | |
| Cost of gas sold | 305.4 | — | — | 305.4 |
| Cost of fuel & purchased power | 187.5 | — | — | 187.5 |
| Other operating | 376.9 | — | (37.8) | 339.1 |
| Depreciation & amortization | 184.2 | 24.3 | 0.3 | 208.8 |
| Taxes other than income taxes | 55.2 | 1.8 | 0.1 | 57.1 |
| Total operating expenses | 1,109.2 | 26.1 | (37.4) | 1,097.9 |
| OPERATING INCOME | 285.0 | 14.6 | (3.0) | 296.6 |
| OTHER INCOME (EXPENSE) | | | | |
| Equity in earnings of consolidated companies | — | 147.0 | (147.0) | — |
| Other – net | 15.7 | 42.7 | (39.7) | 18.7 |
| Total other income (expense) | 15.7 | 189.7 | (186.7) | 18.7 |
| Interest expense | 63.7 | 45.3 | (42.7) | 66.3 |

| | | | | |
|---|---|---|---|---|
| INCOME BEFORE INCOME TAXES | 237.0 | 159.0 | (147.0) | 249.0 |
| Income taxes | 90.0 | (1.9) | — | 88.1 |
| NET INCOME | $ 147.0 | $ 160.9 | $ (147.0) | $ 160.9 |

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

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

| LIABILITIES & SHAREHOLDER'S EQUITY | Subsidiary Guarantors | Parent Company | Eliminations | Consolidated |
|---|---|---|---|---|
| Current Liabilities | | | | |
| Accounts payable | $ 179.4 | $ 42.4 | $ — | $ 221.8 |
| Intercompany payables | 8.3 | — | (8.3) | — |
| Payables to other Vectren companies | 25.2 | 8.1 | — | 33.3 |
| Accrued liabilities | 147.7 | 15.1 | (8.8) | 154.0 |
| Short-term borrowings | — | 179.5 | — | 179.5 |
| Intercompany short-term borrowings | 120.2 | — | (120.2) | — |
| Current maturities of long-term debt | — | 100.0 | — | 100.0 |
| Current maturities of long-term debt due to VUHI | 99.0 | — | (99.0) | — |
| Total current liabilities | 579.8 | 345.1 | (236.3) | 688.6 |
| Long-Term Debt | | | | |
| Long-term debt - net of current maturities & debt subject to tender | 384.5 | 1,095.0 | — | 1,479.5 |
| Long-term debt due to VUHI | 970.7 | — | (970.7) | — |
| Total long-term debt - net | 1,355.2 | 1,095.0 | (970.7) | 1,479.5 |
| Deferred Income Taxes & Other Liabilities | | | | |
| Deferred income taxes | 455.3 | 2.2 | — | 457.5 |
| Regulatory liabilities | 936.1 | 1.1 | — | 937.2 |
| Deferred credits & other liabilities | 210.3 | 2.0 | (0.1) | 212.2 |
| Total deferred credits & other liabilities | 1,601.7 | 5.3 | (0.1) | 1,606.9 |
| Common Shareholder's Equity | | | | |

| | | | | |
|---|---|---|---|---|
| Common stock (no par value) | 890.7 | 877.5 | (890.7 ) | 877.5 |
| Retained earnings | 850.3 | 845.3 | (850.3 ) | 845.3 |
| Total common shareholder's equity | 1,741.0 | 1,722.8 | (1,741.0 ) | 1,722.8 |
| TOTAL LIABILITIES & SHAREHOLDER'S EQUITY | $ 5,277.7 | $ 3,168.2 | $ (2,948.1 ) | $ 5,497.8 |

88

Consolidating Balance Sheet as of December 31, 2016 (in millions):

| ASSETS | Subsidiary Guarantors | Parent Company | Eliminations | Consolidated |
|---|---|---|---|---|
| Current Assets | | | | |
| Cash & cash equivalents | $ 7.6 | $ 1.8 | $ — | $ 9.4 |
| Accounts receivable - less reserves | 102.4 | 0.2 | — | 102.6 |
| Intercompany receivables | 17.5 | 157.1 | (174.6) | — |
| Accrued unbilled revenues | 112.0 | — | — | 112.0 |
| Inventories | 119.0 | — | — | 119.0 |
| Recoverable fuel & natural gas costs | 29.9 | — | — | 29.9 |
| Prepayments & other current assets | 36.5 | 4.4 | (2.3) | 38.6 |
| Total current assets | 424.9 | 163.5 | (176.9) | 411.5 |
| Utility Plant | | | | |
| Original cost | 6,545.4 | — | — | 6,545.4 |
| Less: accumulated depreciation & amortization | 2,562.5 | — | — | 2,562.5 |
| Net utility plant | 3,982.9 | — | — | 3,982.9 |
| Investments in consolidated subsidiaries | — | 1,577.2 | (1,577.2) | — |
| Notes receivable from consolidated subsidiaries | — | 945.4 | (945.4) | — |
| Investments in unconsolidated affiliates | 0.2 | — | — | 0.2 |
| Other investments | 20.9 | 0.4 | — | 21.3 |
| Nonutility plant - net | 1.7 | 163.1 | — | 164.8 |
| Goodwill - net | 205.0 | — | — | 205.0 |
| Regulatory assets | 190.0 | 16.2 | — | 206.2 |
| Other assets | 53.9 | 3.7 | (8.6) | 49.0 |
| TOTAL ASSETS | $ 4,879.5 | $ 2,869.5 | $ (2,708.1) | $ 5,040.9 |

| LIABILITIES & SHAREHOLDER'S EQUITY | Subsidiary Guarantors | Parent Company | Eliminations | Consolidated |
|---|---|---|---|---|
| Current Liabilities | | | | |
| Accounts payable | $ 194.6 | $ 10.8 | $ — | $ 205.4 |
| Intercompany payables | 14.8 | — | (14.8) | — |
| Payables to other Vectren companies | 25.4 | — | — | 25.4 |
| Accrued liabilities | 126.0 | 16.4 | (2.3) | 140.1 |
| Short-term borrowings | — | 194.4 | — | 194.4 |
| Intercompany short-term borrowings | 142.3 | 17.5 | (159.8) | — |
| Current maturities of long-term debt | 49.1 | — | — | 49.1 |
| Total current liabilities | 552.2 | 239.1 | (176.9) | 614.4 |
| Long-Term Debt | | | | |
| Long-term debt - net of current maturities & debt subject to tender | 335.2 | 995.8 | — | 1,331.0 |
| Long-term debt due to VUHI | 945.4 | — | (945.4) | — |
| Total long-term debt - net | 1,280.6 | 995.8 | (945.4) | 1,331.0 |
| Deferred Income Taxes & Other Liabilities | | | | |
| Deferred income taxes | 855.4 | (0.9) | — | 854.5 |
| Regulatory liabilities | 452.4 | 1.3 | — | 453.7 |
| Deferred credits & other liabilities | 161.7 | 10.2 | (8.6) | 163.3 |
| Total deferred credits & other liabilities | 1,469.5 | 10.6 | (8.6) | 1,471.5 |
| Common Shareholder's Equity | | | | |

| | | | | |
|---|---|---|---|---|
| Common stock (no par value) | 844.4 | 831.2 | (844.4 ) | 831.2 |
| Retained earnings | 732.8 | 792.8 | (732.8 ) | 792.8 |
| Total common shareholder's equity | 1,577.2 | 1,624.0 | (1,577.2 ) | 1,624.0 |
| TOTAL LIABILITIES & SHAREHOLDER'S EQUITY | $ 4,879.5 | $ 2,869.5 | $ (2,708.1 ) | $ 5,040.9 |

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

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

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

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

91

Consolidating Statement of Cash Flows for the year ended December 31, 2015 (in millions):

| | Subsidiary Guarantors | Parent Company | Eliminations | Consolidated |
|---|---|---|---|---|
| NET CASH FROM OPERATING ACTIVITIES | $ 460.3 | $ 32.6 | $ — | $ 492.9 |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | | |
| Proceeds from: | | | | |
| Long-term debt, net of issuance costs | 126.8 | 199.0 | (89.5) | 236.3 |
| Additional capital contribution from parent | 6.2 | 6.2 | (6.2) | 6.2 |
| Requirements for: | | | | |
| Dividends to parent | (103.2) | (110.4) | 103.2 | (110.4) |
| Retirement of long-term debt | (20.0) | (75.0) | — | (95.0) |
| Net change in intercompany short-term borrowings | (40.7) | 51.2 | (10.5) | — |
| Net change in short-term borrowings | — | (141.9) | — | (141.9) |
| Net cash from financing activities | (30.9) | (70.9) | (3.0) | (104.8) |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | | |
| Proceeds from: | | | | |
| Consolidated subsidiary distributions | — | 103.2 | (103.2) | — |
| Other investing activities | — | 3.9 | — | 3.9 |
| Requirements for: | | | | |
| Capital expenditures, excluding AFUDC equity | (373.7) | (25.5) | — | (399.2) |
| Consolidated subsidiary investments | — | (6.2) | 6.2 | — |
| Changes in restricted cash | (5.9) | — | — | (5.9) |
| Net change in long-term intercompany notes receivable | — | (89.5) | 89.5 | — |
| Net change in short-term intercompany notes receivable | (51.2) | 40.7 | 10.5 | — |
| Net cash from investing activities | (430.8) | 26.6 | 3.0 | (401.2) |
| Net change in cash & cash equivalents | (1.4) | (11.7) | — | (13.1) |
| Cash & cash equivalents at beginning of period | 6.9 | 12.4 | — | 19.3 |
| Cash & cash equivalents at end of period | $ 5.5 | $ 0.7 | $ — | $ 6.2 |

16. Impact of Recently Issued Accounting Guidance

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 Consolidated Balance Sheets, Consolidated 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. Most of the Company's parent's share-based awards are settled via cash payments, most of which are funded by the Company, and were therefore not impacted by this standard. The Company's parent's adoption of this standard did not have a material impact on the financial statements.

Presentation of Net Periodic Pension and Postretirement Benefit Costs

In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension and postretirement benefit costs. This ASU is effective for annual periods beginning after December 15, 2017, and relevant interim periods. This ASU requires the Company to report the service cost component incurred by the Company's parent 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.

17. Quarterly Financial Data (Unaudited)

Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company’s utility operations.  Summarized quarterly financial data for 2017 and 2016 follows:

| (In millions) | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| 2017 | | | | |
| Results of Operations: | | | | |
| Operating revenues | $425.0 | $285.9 | $279.7 | $392.1 |
| Operating income | 113.5 | 49.7 | 58.0 | 57.5 |
| Net income | 65.9 | 25.5 | 30.8 | 53.6 |
| 2016 | | | | |
| Results of Operations: | | | | |

| | | | | |
|---|---|---|---|---|
| Operating revenues | $423.4 | $279.8 | $291.3 | $383.5 |
| Operating income | 106.8 | 52.2 | 64.0 | 93.5 |
| Net income | 61.1 | 26.3 | 34.9 | 51.3 |

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended December 31, 2017, there have been no changes to the Company’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2017, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2017, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation under the framework in Internal Control — Integrated Framework (2013), the Company concluded that its internal control over financial reporting was effective as of December 31, 2017.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by the Company's registered public accounting firm pursuant to rules of the Securities and Exchange Commission.

ITEM 9B. OTHER INFORMATION

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

Vectren’s Corporate Governance Guidelines; its charters for each committee of its Board of Directors; its Corporate Code of Conduct that covers Vectren's directors are available in the Corporate Governance section of Vectren's website, www.vectren.com. The Corporate Code of Conduct (titled “Corp Code of Conduct”) contains specific acknowledgments pertaining to executive officers. A separate code of conduct (titled “Board Code of Ethics & Code of Conduct”) contains specific codes of ethics pertaining to the Board of Directors. A copy will be mailed upon request to Vectren Corporation Investor Relations, One Vectren Square, Evansville, Indiana 47708. Vectren intends to disclose any amendments to the Corporate Code of Conduct/Board Code of Ethics & Code of Conduct or waivers of the Corporate Code of Conduct on behalf of its directors or officers including, but not limited to, the principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions for the Company on Vectren's website at the internet address set forth above promptly following the date of such amendment or waiver and such information will also be available by mail upon request to the address listed above.

## ITEM 11. EXECUTIVE COMPENSATION

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

## ITEM 14. PRINCIPAL ACCOUNTANT FEES & SERVICES

The following tabulation shows the audit and non-audit fees incurred and payable to Deloitte & Touche LLP (Deloitte) for the years ending December 31, 2017 and 2016. The fees presented below represent total Vectren Corporation (Vectren or the Company's parent) fees, the majority of which are allocated to the Company.

| | 2017 | 2016 |
|---|---|---|
| Audit Fees(1) | $1,889,575 | $1,840,661 |
| Audit-Related Fees(2) | 106,370 | 72,600 |
| Tax Fees(3) | 110,665 | 126,499 |
| Total Fees Paid to Deloitte(4) | $2,106,610 | $2,039,760 |

(1) Aggregate fees incurred and payable to Deloitte for professional services rendered for the audits of the Company’s parent and the Company's 2017 and 2016 fiscal year annual financial statements and the review of financial statements included in their Forms 10-K or 10-Q filed during Vectren’s 2017 and 2016 fiscal years and audit fees related to the stand alone audits of certain nonutility consolidated subsidiaries of the Company's parent. The amount includes fees related to the attestation to Vectren's assertion pursuant to Section 404 of the Sarbanes-Oxley

Act of 2002. In addition, this amount includes the reimbursement of out-of-pocket costs incurred related to the provision of these services totaling $108,175 and $179,461 in 2017 and 2016, respectively.

(2) Audit-related fees consisted principally of reviews related to various financing transactions, regulatory filings, and consultation on various accounting issues.

(3) Tax fees consisted of fees paid to Deloitte for the review of tax returns and consultation on other tax matters of the Company's parent and of its consolidated subsidiaries. In addition, this amount includes the reimbursement of out-of-pocket costs incurred related to the provision of these services totaling $7,746 and $8,999 in 2017 and 2016, respectively.

(4) Pursuant to its charter, the Audit and Risk Management Committee of Vectren's Board of Directors (Audit Committee), is responsible for selecting, approving professional fees and overseeing the independence, qualifications and performance of the independent registered public accounting firm. The Audit Committee has adopted a formal policy with respect to the pre-approval of audit and permissible non-audit services provided by the independent registered public accounting firm. Pre-approval is assessed on a case-by-case basis. In assessing requests for services to be provided by the independent registered public accounting firm, the Audit Committee considers whether such services are consistent with the auditors' independence, whether the independent registered public accounting firm is likely to provide the most effective and efficient service based upon the firm's familiarity with the Company's parent and its consolidated subsidiaries, and whether the service could enhance the ability of the Company's parent to manage or control risk or improve audit quality. The audit-related, tax and other services provided by Deloitte in the last year and related fees were approved by the Audit Committee in accordance with this policy.

PART IV

ITEM 15. EXHIBITS & FINANCIAL STATEMENT SCHEDULES

List of Documents Filed as Part of This Report

Consolidated Financial Statements
The consolidated financial statements and related notes, together with the report of Deloitte & Touche LLP, appear in Part II "Item 8 Financial Statements and Supplementary Data" of this Form 10-K.

Supplemental Schedules
For the years ended December 31, 2017, 2016, and 2015, the Company's Schedule II -- Valuation and Qualifying Accounts Consolidated Financial Statement Schedules is presented herein. The report of Deloitte & Touche LLP on the schedule may be found in Item 8. All other schedules are omitted as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or related notes in Item 8.

SCHEDULE II
Vectren Utility Holdings, Inc. and Subsidiaries
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

| Column A | Column B | Column C | | Column D | Column E |
|---|---|---|---|---|---|
| | | Additions | | | |
| Description | Balance at Beginning Of Year | Charged to Expenses | Charged to Other Accounts | Deductions from Reserves, Net | Balance at End of Year |
| (In millions) | | | | | |
| VALUATION AND QUALIFYING ACCOUNTS: | | | | | |
| Year 2017 – Accumulated provision for uncollectible accounts | $ 4.1 | $ 5.7 | $ — | $ 5.9 | $ 3.9 |
| Year 2016 – Accumulated provision for uncollectible accounts | $ 3.0 | $ 6.6 | $ — | $ 5.5 | $ 4.1 |
| Year 2015 – Accumulated provision for uncollectible accounts | $ 3.9 | $ 6.9 | $ — | $ 7.8 | $ 3.0 |

List of Exhibits

The Company has incorporated by reference herein certain exhibits as specified below pursuant to Rule 12b-32 under the Exchange Act. Exhibits for the Company attached to this filing filed electronically with the SEC are listed below.

Vectren Utility Holdings, Inc.
Form 10-K
Attached Exhibits

The following Exhibits were filed electronically with the SEC with this filing.

| Exhibit Number | Document |
|---|---|
| 21.1 | List of Company’s Significant Subsidiaries |
| 31.1 | Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32 | Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema |
| 101.CAL | XBRL Taxonomy Calculation Linkbase |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase |

INDEX TO EXHIBITS

3. Articles of Incorporation and By-Laws

3.1 Articles of Incorporation of Vectren Utility Holdings, Inc. (Filed and designated in Registration Statement on Amendment 3 to Form 10, File No. 1-16739, as Exhibit 3.1)

3.2 By-Laws of Vectren Utility Holdings, Inc. as most recently amended as of October 1, 2017 (filed and designated in Form 8-K, dated September 25, 2017, File No. 1-15467, as Exhibit 3.1)

4. Instruments Defining the Rights of Security Holders, Including Indentures

4.1 Mortgage and Deed of Trust dated as of April 1, 1932 between Southern Indiana Gas and Electric Company and Bankers Trust Company, as Trustee, and Supplemental Indentures thereto dated August 31, 1936, October 1, 1937, March 22, 1939, July 1, 1948, June 1, 1949, October 1, 1949, January 1, 1951, April 1, 1954, March 1, 1957, October 1, 1965, September 1, 1966, August 1, 1968, May 1, 1970, August 1, 1971, April 1, 1972, October 1, 1973, April 1, 1975, January 15, 1977, April 1, 1978, June 4, 1981, January 20, 1983, November 1, 1983, March 1, 1984, June 1, 1984, November 1, 1984, July 1, 1985, November 1, 1985, June 1, 1986. (Filed and designated in Registration No. 2-2536 as Exhibits B-1 and B-2; in Post-effective Amendment No. 1 to Registration No. 2-62032 as Exhibit (b)(4)(ii), in Registration No. 2-88923 as Exhibit 4(b)(2), in Form 8-K, File No. 1-3553, dated June 1, 1984 as Exhibit (4), File No. 1-3553, dated March 24, 1986 as Exhibit 4-A, in Form 8-K, File No. 1-3553, dated June 3, 1986 as Exhibit (4).) July 1, 1985 and November 1, 1985 (Filed and designated in Form 10-K, for the fiscal year 1985, File No. 1-3553, as Exhibit 4-A.) November 15, 1986 and January 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1986, File No. 1-3553, as Exhibit 4-A.) December 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1987, File No. 1-3553, as Exhibit 4-A.) December 13, 1990. (Filed and designated in Form 10-K, for the fiscal year 1990, File No. 1-3553, as Exhibit 4-A.) April 1, 1993. (Filed and designated in Form 8-K, dated April 13, 1993, File No. 1-3553, as Exhibit 4.) June 1, 1993 (Filed and designated in Form 8-K, dated June 14, 1993, File No. 1-3553, as Exhibit 4.) May 1, 1993. (Filed and designated in Form 10-K, for the fiscal year 1993, File No. 1-3553, as Exhibit 4(a).) July 1, 1999. (Filed and designated in Form 10-Q, dated August 16, 1999, File No. 1-3553, as Exhibit 4(a).) March 1, 2000. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 4.1.) August 1, 2004. (Filed and designated in Form 10-K for the year ended December 31, 2004, File No. 1-15467, as Exhibit 4.1.) October 1, 2004. (Filed and designated in Form 10-K for the year ended December 31, 2004, File No. 1-15467, as Exhibit 4.2.) April 1, 2005 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.1) March 1, 2006 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.2) December 1, 2007 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.3) August 1, 2009 (Filed and designated in Form 10-K for the year ended December 31, 2009, File No 1-15467, as Exhibit 4.1) April 1, 2013 (Filed and designated in Form 8-K dated April 30, 2013, File No. 1-15467, as Exhibit 4.1) September 1, 2014 (filed and designated in Form 8-K dated September 25, 2014 File No. 1-15467, as Exhibit 4.1) September 1, 2015 (filed and designated in Form 8-K dated September 10, 2015 File No. 1-15467, as Exhibit 4.1)

4.2 Indenture dated February 1, 1991, between Indiana Gas and U.S. Bank Trust National Association (formerly known as First Trust National Association, which was formerly known as Bank of America Illinois, which was formerly known as Continental Bank, National Association. Inc.'s. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494.); First Supplemental Indenture thereto dated as of February 15, 1991. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494, as Exhibit 4(b).); Second Supplemental Indenture thereto dated as of September 15, 1991, (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File No. 1-6494, as Exhibit 4(b).); Third supplemental Indenture thereto dated as of September 15, 1991 (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File No. 1-6494, as Exhibit 4(c).); Fourth Supplemental Indenture thereto dated as of

December 2, 1992, (Filed and designated in Current Report on Form 8-K filed December 8, 1992, File No. 1-6494, as Exhibit 4(b).); Fifth Supplemental Indenture thereto dated as of December 28, 2000, (Filed and designated in Current Report on Form 8-K filed December 27, 2000, File No. 1-6494, as Exhibit 4.)

| | |
|---|---|
| 4.3 | Indenture dated October 19, 2001, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.1); First Supplemental Indenture, dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.2); Second Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 29, 2001, File No. 1-16739, as Exhibit 4.1); Third Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated July 24, 2003, File No. 1-16739, as Exhibit 4.1); Fourth Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 18, 2005, File No. 1-16739, as Exhibit 4.1). Form of Fifth Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas & Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 16, 2006, File No. 1-16739, as Exhibit 4.1). Sixth Supplemental Indenture, dated March 10, 2008, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank National Association (Filed and designated in Form 8-K, dated March 10, 2008, File No. 1-16739, as Exhibit 4.1) |
| 4.4 | Note Purchase Agreement, dated April 7, 2009, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated April 7, 2009 File No. 1-15467, as Exhibit 4.5) |
| 4.5 | Note Purchase Agreement, dated April 5, 2011, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated April 8, 2011 File No. 1-15467, as Exhibit 4.1) |
| 4.6 | Note Purchase Agreement, dated November 15, 2011, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated November 17, 2011 File No. 1-15467, as Exhibit 4.1) |
| 4.7 | Note Purchase Agreement, dated December 20, 2012, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated December 21, 2012 File No. 1-15467, as Exhibit 4.1) |
| 4.8 | Note Purchase Agreement, dated August 22, 2013, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. and the purchasers named therein. (Filed and designated in Form 8-K dated August 2, 2013, File No. 1-15467, as Exhibit 4.1) |
| 4.9 | Note Purchase Agreement, dated June 11, 2015, between Vectren Utility Holding, Inc. and each of the purchasers named therein. (Filed and designated in Form 8-K dated June 12, 2015 File No. 1-15467, as Exhibit 4.1). |
| 4.10 | Note Purchase Agreement, dated July 14, 2017, between Vectren Utility Holdings, Inc. (VUHI), certain subsidiaries of VUHI as guarantors and each of the purchasers named therein. (Filed and designated in Form 8-K dated July 17, 2017 File No. 1-15467, as Exhibit 4.1). |
| 4.11 | Bond Purchase and Covenants Agreement, dated September 14, 2017, between Southern Indiana Gas and Electric Company and PNC Bank, National Association. (Filed and designated in Form 8-K dated September 25, 2017, File No 1-5467, as Exhibit 4.1). |

10. Material Contracts

| | |
|---|---|
| 10.1 | Vectren Corporation At Risk Compensation Plan effective May 1, 2001, (as most recently amended and restated as of May 24, 2016). (Filed and designated in Form 10Q for the quarter ended June 30, 2016, File No. 1-15467, as Exhibit 10.1.) |
| 10.2 | Vectren Corporation Nonqualified Deferred Compensation Plan, as amended and restated effective January 1, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.32.) |
| 10.3 | Vectren Corporation Nonqualified Deferred Compensation Plan, effective January 1, 2005. (Filed and designated in Form 8-K dated September 29, 2008, File No. 1-15467, as Exhibit 10.3.) |
| 10.4 | Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees (As Amended and Restated Effective January 1, 2005).(Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.1.) |
| 10.5 | Vectren Corporation Specimen Waiver, effective October 3, 2013, to the Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees. (Filed and designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-15467, as Exhibit 10.1.) |
| 10.6 | Vectren Corporation Nonqualified Defined Benefit Restoration Plan (As Amended and Restated Effective January 1, 2005). (Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.2.) |
| 10.7 | Vectren Corporation specimen change in control agreement dated December 31, 2011. (Filed and designated in Form 8-K, dated January 5, 2012, File No. 1-15467, as Exhibit 10.1) |
| 10.8 | Amendment Number One to the Vectren Corporation specimen change in control agreement dated December 31, 2012. (Filed and designated in Form 10-K, for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.1) |
| 10.9 | Vectren Corporation Executive Severance Plan agreement dated December 31, 2011, as most recently amended and restated as of February 21, 2017. (Filed and designated in Form 10-K, for the year ended December 31, 2016, File No. 1-15467, as Exhibit 10.11). The severance plan differs among the named executive officers only to the extent where severance benefits are provided in the amount of two times base salary for Mr. Chapman and one and one half times base salary for Messer's Schach and Christian and Ms. Hardwick. |
| 10.10 | Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC, effective April 1, 2012. Contract assigned to ETC ProLiance Energy, LLC on June 18, 2013. (Filed and designated Form 10-K, for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.3.) |
| 10.11 | Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, effective April 1, 2012. Contract assigned to ETC ProLiance Energy, LLC on June 18, 2013. (Filed and designated Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.4.) |
| 10.12 | Amendment Number Two to the Vectren Corporation Change in Control Agreement (specimen), dated October 1, 2014. The specimen agreement differs among the named executive officers only to the extent change in control benefits are provided in the amount of three times base salary and bonus for Mr. Chapman and two times base salary and bonus for Messer's Benkert and Christian and one and a half times base salary and bonus for Ms. Hardwick and Mr. Schach. (Filed and designated in Form 8-K, dated September 29, 2014, File No. 1-15467, as Exhibit 10.1) |
| 10.13 | Vectren Corporation At Risk Compensation Plan Stock Unit Awards Award Agreement (Officer). (Filed and designated in Form 8-K, dated December 23, 2014, File No. 1-15467, as Exhibit 10.1) |
| 10.14 | Grant Agreement for Non-Employee Director Stock Grant, dated December 31, 2014. (Filed and designated in Form 8-K, dated January 2, 2015, File No. 1-15467, as Exhibit 10.1) |

| | |
|---|---|
| 10.15 | Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-15467, as Exhibit 10.2.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted. |
| 10.16 | Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-15467, as Exhibit 10.3.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted. |
| 10.17 | Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2015. Contract assigned to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-Q dated March 31, 2015, File No. 1-15467, as Exhibit 10.4.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted. |
| 10.18 | Vectren Director and Officer Indemnification Agreement (specimen) (Filed and designated in Form 10-K, for the year ended December 31, 2015, File No. 1-15467, as Exhibit 10.24) |
| 10.19 | Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 1, 2017. (Filed and designated in Form 10-K, for the year ended December 31, 2016, File No. 1-15467, as Exhibit 10.22) |
| 10.20 | Credit Agreement, dated as of July 14, 2017, among Vectren Utility Holdings, Inc., as borrower (VUHI); certain subsidiaries of VUHI, as guarantors; Bank of America, N.A., as administrative agent, swing line lender and a letter of credit issuer; Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K dated July 17, 2017 File No. 1-5467, as Exhibit 10.1). |
| 10.21 | Amendment to Agreement for Unit Four, made effective as of September 21, 2017, by and between Alcoa Power Generating Inc., and Southern Indiana Gas and Electric Company. (Filed and Designated in Form 8-K dated September 25, 2017, File No. 1-15467, as Exhibit 10.1). |

21. Subsidiaries of the Company
The list of the Company's significant subsidiaries is attached hereto as Exhibit 21.1. (Filed herewith.)

31. Certification Pursuant To Section 302 of the Sarbanes-Oxley Act of 2002
Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 31.1 (Filed herewith.)

Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 31.2 (Filed herewith.)

32. Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
Certification Pursuant To Section 906 of the Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 32 (Filed herewith.)

101 Interactive Data File
101.INS XBRL Instance Document (Furnished herewith.)
101.SCH XBRL Taxonomy Extension Schema (Furnished herewith.)
101.CAL XBRL Taxonomy Extension Calculation Linkbase (Furnished herewith.)

102

| | |
|---|---|
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase (Furnished herewith.) |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase (Furnished herewith.) |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase (Furnished herewith.) |

SIGNATURES

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

VECTREN UTILITY HOLDINGS, INC.

Dated March 8, 2018 /s/ Carl L. Chapman
Carl L. Chapman
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ Carl L. Chapman<br>Carl L. Chapman | Chairman and Chief Executive Officer<br>(Principal Executive Officer) | March 8, 2018 |
| /s/ M. Susan Hardwick<br>M. Susan Hardwick | Executive Vice President, Chief Financial Officer, and Director<br>(Principal Accounting and Financial Officer) | March 8, 2018 |
| /s/ Eric J. Schach<br>Eric J. Schach | President and Director | March 8, 2018 |
| /s/ Ronald E. Christian<br>Ronald E. Christian | Executive Vice President, Chief Legal and External Affairs Officer, Secretary, and Director | March 8, 2018 |