VECTREN CORP
Form 10-Q
August 04, 2016

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

FORM 10-Q

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

For the quarterly period ended June 30, 2016

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

For the transition period from __________________ to __________________

Commission file number: 1-15467

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

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

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

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

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

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

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

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

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

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

| | | |
|---|---|---|
| Common Stock- Without Par Value | 82,835,860 | July 29, 2016 |
| Class | Number of Shares | Date |

Access to Information

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

| | | |
|---|---|---|
| Mailing Address:<br>One Vectren Square<br>Evansville, Indiana 47708 | Phone Number:<br>(812) 491-4000 | Investor Relations Contact:<br>M. Naveed Mughal<br>Treasurer and Vice President, Investor Relations<br>vvcir@vectren.com |

Definitions

| | |
|---|---|
| AFUDC: allowance for funds used during construction | IDEM: Indiana Department of Environmental Management |
| ASC: Accounting Standards Codification | IURC: Indiana Utility Regulatory Commission |
| ASU: Accounting Standards Update | kV: Kilovolt |
| BTU / MMBTU: British thermal units / millions of BTU | MCF / BCF: thousands / billions of cubic feet |
| DOT: Department of Transportation | MDth / MMDth: thousands / millions of dekatherms |
| EPA: Environmental Protection Agency | MISO: Midcontinent Independent System Operator |
| FAC: Fuel Adjustment Clause | MW: megawatts |
| FASB: Financial Accounting Standards Board | MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours) |
| FERC: Federal Energy Regulatory Commission | OUCC: Indiana Office of the Utility Consumer Counselor |
| GAAP: Generally Accepted Accounting Principles | PUCO: Public Utilities Commission of Ohio |
| GCA: Gas Cost Adjustment | XBRL: eXtensible Business Reporting Language |

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

| | June 30, 2016 | December 31, 2015 |
|---|---|---|
| ASSETS | | |
| Current Assets | | |
| Cash & cash equivalents | $15.9 | $ 74.7 |
| Accounts receivable - less reserves of $6.0 & $5.6, respectively | 176.5 | 227.5 |
| Accrued unbilled revenues | 96.0 | 142.5 |
| Inventories | 127.8 | 133.7 |
| Recoverable fuel & natural gas costs | 18.4 | — |
| Prepayments & other current assets | 62.0 | 81.0 |
| Total current assets | 496.6 | 659.4 |
| Utility Plant | | |
| Original cost | 6,298.5 | 6,090.4 |
| Less: accumulated depreciation & amortization | 2,493.0 | 2,415.5 |
| Net utility plant | 3,805.5 | 3,674.9 |
| Investments in unconsolidated affiliates | 20.8 | 20.9 |
| Other utility & corporate investments | 32.8 | 31.2 |
| Other nonutility investments | 16.1 | 16.2 |
| Nonutility plant - net | 430.6 | 414.6 |
| Goodwill | 293.5 | 293.5 |
| Regulatory assets | 274.4 | 249.4 |
| Other assets | 40.8 | 39.9 |
| TOTAL ASSETS | $5,411.1 | $ 5,400.0 |

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

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

| | June 30, 2016 | December 31, 2015 |
|---|---|---|
| LIABILITIES & SHAREHOLDERS' EQUITY | | |
| Current Liabilities | | |
| Accounts payable | $239.8 | $ 248.8 |
| Refundable fuel & natural gas costs | — | 7.9 |
| Accrued liabilities | 170.5 | 183.6 |
| Short-term borrowings | 45.2 | 14.5 |
| Current maturities of long-term debt | — | 73.0 |
| Total current liabilities | 455.5 | 527.8 |
| Long-term Debt - Net of Current Maturities | 1,713.5 | 1,712.9 |
| Deferred Credits & Other Liabilities | | |
| Deferred income taxes | 854.4 | 805.4 |
| Regulatory liabilities | 448.2 | 433.9 |
| Deferred credits & other liabilities | 238.3 | 236.2 |
| Total deferred credits & other liabilities | 1,540.9 | 1,475.5 |
| Commitments & Contingencies (Notes 7-11) | | |
| Common Shareholders' Equity | | |
| Common stock (no par value) – issued & outstanding 82.8 & 82.8, respectively | 725.9 | 722.8 |
| Retained earnings | 976.5 | 962.2 |
| Accumulated other comprehensive (loss) | (1.2) | (1.2) |
| Total common shareholders' equity | 1,701.2 | 1,683.8 |
| TOTAL LIABILITIES & SHAREHOLDERS' EQUITY | $5,411.1 | $ 5,400.0 |

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

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| OPERATING REVENUES | | | | |
| Gas utility | $132.0 | $128.6 | $413.1 | $481.5 |
| Electric utility | 147.7 | 147.8 | 289.8 | 301.7 |
| Nonutility | 254.0 | 274.6 | 415.5 | 474.0 |
| Total operating revenues | 533.7 | 551.0 | 1,118.4 | 1,257.2 |
| OPERATING EXPENSES | | | | |
| Cost of gas sold | 34.0 | 36.4 | 145.5 | 208.4 |
| Cost of fuel & purchased power | 45.2 | 47.0 | 89.4 | 97.0 |
| Cost of nonutility revenues | 82.9 | 93.4 | 138.2 | 157.7 |
| Other operating | 229.7 | 225.0 | 430.7 | 456.2 |
| Depreciation & amortization | 64.1 | 63.7 | 128.0 | 126.6 |
| Taxes other than income taxes | 13.9 | 12.6 | 31.5 | 32.3 |
| Total operating expenses | 469.8 | 478.1 | 963.3 | 1,078.2 |
| OPERATING INCOME | 63.9 | 72.9 | 155.1 | 179.0 |
| OTHER INCOME | | | | |
| Equity in earnings (losses) of unconsolidated affiliates | 0.1 | — | (0.2) | — |
| Other income – net | 7.8 | 5.0 | 14.5 | 10.5 |
| Total other income | 7.9 | 5.0 | 14.3 | 10.5 |
| INTEREST EXPENSE | 21.3 | 20.9 | 43.3 | 41.9 |
| INCOME BEFORE INCOME TAXES | 50.5 | 57.0 | 126.1 | 147.6 |
| INCOME TAXES | 18.2 | 21.2 | 45.5 | 54.8 |
| NET INCOME AND COMPREHENSIVE INCOME | $32.3 | $35.8 | $80.6 | $92.8 |
| WEIGHTED AVERAGE COMMON SHARES OUTSTANDING | 82.8 | 82.6 | 82.8 | 82.6 |
| DILUTED COMMON SHARES OUTSTANDING | 82.8 | 82.6 | 82.8 | 82.6 |
| BASIC AND DILUTED EARNINGS PER SHARE OF COMMON STOCK | $0.39 | $0.43 | $0.97 | $1.12 |
| DIVIDENDS DECLARED PER SHARE OF COMMON STOCK | $0.40 | $0.38 | $0.80 | $0.76 |

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

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

| | Six Months Ended June 30, | |
|---|---|---|
| | 2016 | 2015 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | |
| Net income | $80.6 | $92.8 |
| Adjustments to reconcile net income to cash from operating activities: | | |
| Depreciation & amortization | 128.0 | 126.6 |
| Deferred income taxes & investment tax credits | 48.9 | 28.7 |
| Provision for uncollectible accounts | 4.1 | 4.5 |
| Expense portion of pension & postretirement benefit cost | 1.9 | 3.1 |
| Other non-cash items - net | 4.0 | 3.1 |
| Changes in working capital accounts: | | |
| Accounts receivable & accrued unbilled revenues | 93.4 | 26.1 |
| Inventories | 5.9 | 6.0 |
| Recoverable/refundable fuel & natural gas costs | (26.3 ) | 30.0 |
| Prepayments & other current assets | 18.8 | 59.4 |
| Accounts payable, including to affiliated companies | (23.6 ) | (71.7 ) |
| Accrued liabilities | (13.1 ) | (11.5 ) |
| Employer contributions to pension & postretirement plans | (17.1 ) | (22.3 ) |
| Changes in noncurrent assets | (17.5 ) | (5.1 ) |
| Changes in noncurrent liabilities | 5.3 | (3.1 ) |
| Net cash provided by operating activities | 293.3 | 266.6 |
| CASH FLOWS FROM FINANCING ACTIVITIES | | |
| Proceeds from dividend reinvestment plan & other common stock issuances | 3.0 | 3.0 |
| Requirements for: | | |
| Dividends on common stock | (66.3 ) | (62.8 ) |
| Retirement of long-term debt | (73.0 ) | (5.0 ) |
| Net change in short-term borrowings | 30.7 | (60.0 ) |
| Net cash used in financing activities | (105.6) | (124.8) |
| CASH FLOWS FROM INVESTING ACTIVITIES | | |
| Proceeds from sale of assets and other collections | 1.4 | 4.1 |
| Requirements for: | | |
| Capital expenditures, excluding AFUDC equity | (248.0) | (207.9) |
| Business acquisitions and other costs | — | (13.1 ) |
| Changes in restricted cash | 0.1 | — |
| Net cash used in investing activities | (246.5) | (216.9) |
| Net change in cash & cash equivalents | (58.8 ) | (75.1 ) |
| Cash & cash equivalents at beginning of period | 74.7 | 86.4 |
| Cash & cash equivalents at end of period | $15.9 | $11.3 |

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

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

1. Organization and Nature of Operations

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

Indiana Gas provides energy delivery services to approximately 588,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 318,000 natural gas customers located near Dayton in west central Ohio.

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

2. Basis of Presentation

The interim condensed consolidated financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These interim condensed consolidated financial statements and related notes should be read in conjunction with the Company’s audited annual consolidated financial statements for the year ended December 31, 2015, filed with the Securities and Exchange Commission on February 23, 2016, on Form 10-K. Because of the seasonal nature of the Company’s operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

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

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3. Earnings Per Share

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

Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of stock options and other equity based instruments to the extent the effect is dilutive.

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

| | Three Months Ended | | Six Months Ended | |
|---|---|---|---|---|
| | June 30, | | June 30, | |
| (In millions, except per share data) | 2016 | 2015 | 2016 | 2015 |
| Numerator: | | | | |
| Reported net income (Numerator for Basic and Diluted EPS) | $32.3 | $35.8 | $80.6 | $92.8 |
| Denominator: | | | | |
| Weighted average common shares outstanding (Denominator for Basic and Diluted EPS) | 82.8 | 82.6 | 82.8 | 82.6 |
| Basic and Diluted EPS | $0.39 | $0.43 | $0.97 | $1.12 |

As of June 30, 2016, the Company no longer has any stock options outstanding. For the three and six months ended June 30, 2015, all stock options were dilutive and immaterial. For the three and six months ended June 30, 2016 and 2015, all equity based instruments were dilutive and immaterial.

4. Excise and 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, which totaled $5.5 million and $5.4 million in the three months ended June 30, 2016 and 2015, respectively, as a component of operating revenues. During the six months ended June 30, 2016 and 2015, these taxes totaled $14.9 million and $17.1 million, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Retirement Plans & Other Postretirement Benefits

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

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Net Periodic Benefit Costs

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

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Service cost | $1.7 | $2.0 | $— | $0.1 |
| Interest cost | 3.7 | 3.7 | 0.5 | 0.5 |
| Expected return on plan assets | (5.7 ) | (5.7 ) | — | — |
| Amortization of prior service cost | 0.1 | 0.2 | (0.8 ) | (0.8 ) |
| Amortization of actuarial loss | 1.8 | 2.1 | — | 0.2 |
| Net periodic cost (benefit) | $1.6 | $2.3 | $(0.3) | $— |

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Benefits | |
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Service cost | $3.5 | $4.0 | $0.1 | $0.2 |
| Interest cost | 7.3 | 7.3 | 0.9 | 1.0 |
| Expected return on plan assets | (11.4) | (11.3) | — | — |
| Amortization of prior service cost | 0.2 | 0.4 | (1.5 ) | (1.5 ) |
| Amortization of actuarial loss | 3.6 | 4.2 | — | 0.3 |
| Net periodic cost (benefit) | $3.2 | $4.6 | $(0.5) | $— |

Employer Contributions to Qualified Pension Plans

In 2016, the Company has made $15 million in contributions to its qualified pension plans.

6. Supplemental Cash Flow Information

As of June 30, 2016 and December 31, 2015, the Company has accruals related to utility and nonutility plant purchases totaling approximately $31.7 million and $19.4 million, respectively.

7. Investment in ProLiance Holdings, LLC

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

The Company's investment at June 30, 2016, shown at its 61 percent ownership share of the individual net assets of ProLiance, is as follows.

| (In millions) | As of June 30, 2016 |
|---|---|
| Cash | $2.1 |
| Investment in LA Storage | 22.3 |
| Other midstream asset investment | 5.0 |
| Total investment in ProLiance | $29.4 |
| Included in: | |
| Investments in unconsolidated affiliates | $19.3 |
| Other nonutility investments | $10.1 |

LA Storage

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

Approximately 12 Bcf of the storage, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to further develop the caverns. The timing and extent of development of these caverns is dependent on market conditions, including pricing, need for storage capacity, and development of the liquefied natural gas market, among other factors. To date, development activity has been modest due to current low demand for storage facilities. The development of the storage market and related pricing are critical assumptions in the analysis of the recoverability of the investment's carrying value. As of June 30, 2016 and December 31, 2015, ProLiance's investment in the joint venture was $36.5 million and $36.4 million, respectively.

8. Commitments & Contingencies

Performance Guarantees & Product Warranties

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at June 30, 2016, there are 42 open surety bonds supporting future performance. The average face amount of these obligations is $9.6 million, and the largest obligation has a face amount of $51.0 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various subcontractors. At June 30, 2016, approximately 45 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented. Since inception, ESG has paid a de minimis amount on performance obligations.

Corporate Guarantees
The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At June 30, 2016, parent level guarantees support a maximum of $250 million of ESG’s performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees.

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

In addition, the Company has other guarantees outstanding, including letters of credit, supporting other consolidated subsidiary operations.

While there can be no assurance that the Company guarantee provisions will not be called upon, historically no such provisions have been called upon, and further, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

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

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

9. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
The Company monitors and maintains its natural gas distribution system to ensure natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are a 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.

In April 2011, Indiana Senate Bill 251 (Senate Bill 251) was signed into Indiana law. The law 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, 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.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation 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 that, 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 and recovered 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.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. The 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 Condensed 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 June 30, 2016 and December 31, 2015, the Company has regulatory assets totaling $21.2 million and $19.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company’s seven-year capital investment plan discussed further below.

Requests for Recovery under Indiana Regulatory Mechanisms
On August 27, 2014, the IURC issued an Order (August 2014 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 via a fixed monthly charge per residential customer.

Subsequent to the August 2014 Order, the Company filed and received Orders on each of its semi-annual updates, which recover in rates investments associated with the approved programs. In October 2015, the Company submitted its third semi-annual filing, seeking approval of the recovery in rates of investments made through June 30, 2015, and updates to the approved seven-year capital investment plan. On March 30, 2016, the IURC issued an Order (March 2016 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 projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, one project totaling about $65 million involving a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area 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 this law. In the March 2016 Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. The Company believes that such plan updates should be expected to accommodate new projects that emerge during the term of the plan as ongoing risk assessments determine that new projects are required. The Company filed an appeal of the March 2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. The outcome of the appeal is expected in 2017.

On June 29, 2016, the IURC issued an Order (June 2016 Order) approving the inclusion in rates of investments made from July 2015 to December 2015. Through the June 2016 Order, approximately $262 million of the Plan's $890 million total has been spent and included for recovery as of December 31, 2015.

At June 30, 2016 and December 31, 2015, the Company has regulatory assets related to the Plan totaling $46.7 million and $28.6 million, respectively, associated with the return on investment as well as the deferral of depreciation and other operating expenses.

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 and certain other infrastructure. 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. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. 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 over the next five years. 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; however, the remaining capital expenditure plan, estimated to be approximately $90 million for the remainder of 2016 and 2017, is not expected to exceed those caps. 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 under the DRR totaling $220.7 million as of June 30, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $21.3 million and $18.2 million at June 30, 2016 and December 31, 2015, respectively. On May 2, 2016, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2015. A procedural schedule has been set in this proceeding and the Company expects an order by September 2016.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will not file a general rate case for the inclusion in rate base of the above costs until the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining two-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have 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. As of June 30, 2016, the Company's deferrals have not reached this bill impact cap. On May 2, 2016, 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 2016.

Pipeline and Hazardous Materials Safety Administration (PHMSA)

On March 18, 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements from the 2011 Pipeline Safety Act and sets out more stringent requirements than anticipated. The Company is evaluating the impact the proposed rules would have on the Company's transmission integrity management program and the design, construction, and repair of transmission pipeline assets, including the potential for additional capital expenditures and increase in operation and maintenance expense. The Company believes that such compliance costs would be considered federally mandated costs and therefore should be recoverable from customers using the regulatory recovery mechanisms referenced above.

10. Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order (January 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) related to sulfur trioxide emissions from the EPA. As of June 30, 2016, approximately $31 million has been spent on equipment to control mercury in both air and water emissions, and $37 million to address the issues raised in the NOV. The total investment is estimated to be between $70 million and $75 million. The Order approved the Company's request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment occurring in 2015 and 2016. As of June 30, 2016, the Company has approximately $4.6 million deferred related to depreciation, property tax, and operating expense, and $1.9 million deferred related to post-in-service carrying costs.

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 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 (approximately $35 million) but remanded the case back to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order. The basis for the appeal will not be known until the appeal brief is filed later this year. The Company believes the IURC decision is well founded and will ultimately be upheld.

SIGECO Electric Demand Side Management (DSM) Program Filing
On August 31, 2011, the IURC issued an Order approving an initial three-year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the six months ended June 30, 2016 and 2015, the Company recognized electric utility revenue of $5.4 million and $4.8 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that had been conducted to meet the energy savings requirements established by the IURC in 2009. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company's eligible industrial load has opted out of participation in the applicable energy efficiency programs. The Company filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs for 2015 were implemented during the first quarter of 2015.

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 (Senate Bill 412) into law requiring electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also permits 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. In September 2015, the Company received an Order to continue offering and recovering the associated cost of its 2015 programs until March 31, 2016. In October 2015, the OUCC and Citizens Action Coalition of Indiana filed testimony recommending the rejection of the Company's plan, contending it was not reasonable under the terms of Senate Bill 412 due to the program design and the Company's proposal to recover lost revenues and incentives associated with the measures. Vectren filed rebuttal testimony in October 2015 defending the plan's compliance with Senate Bill 412.

On March 23, 2016, the IURC issued an Order approving the Company's 2016-2017 energy efficiency programs. The Order provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that 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 follows three other recent IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company is committed to continuing
to promote and drive participation in its 2016-2017 energy efficiency programs and beyond and has therefore appealed this lost margin recovery restriction.

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. The joint parties seek to reduce the 12.38 percent ROE used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. A second customer complaint case was filed on February 11, 2015 as the maximum FERC-allowed refund period for the November 12, 2013 case ended February 11, 2015. This second complaint covers the period February 12, 2015 through May 11, 2016. As of June 30, 2016, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $138.5 million at June 30, 2016.

These joint complaints are similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a new calculation methodology. The new methodology is based on a two-step discounted cash flow analysis that uses short-term and long-term growth projections in calculating ROE rates for a proxy group of electric utilities. The FERC has stated that it expects future decisions on pending complaints related to similar ROE issues to be guided by the New England transmission decision.

The FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable but denied the portion of the complaint addressing the equity component of the capital structure. An initial decision from its administrative law judge was received on December 22, 2015, authorizing the transmission owners to collect a Base ROE of 10.32 percent from November 12, 2013 through February 11, 2015 (the "first refund period"). The FERC is expected to rule on the proposed order in late 2016. An initial decision from the FERC administrative law judge in the second complaint case was received on June 30, 2016, authorizing the transmission owners to collect a Base ROE of 9.70 percent from February 12, 2015 through May 11, 2016 (the "second refund period"). The FERC is expected to rule on the proposed order in the second complaint case in 2017.

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 FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

The Company has established a reserve considering the initial decisions and the approved 50 basis points adder.

11. Environmental Matters

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

With the trend toward stricter standards, greater regulation, and more extensive permit requirements, the Company's investment in compliant infrastructure, and the associated operating costs have increased and are expected to increase in the future. 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.

Air Quality

Mercury and Air Toxics (MATS) Rule
On December 21, 2011, the EPA finalized the utility MATS rule. 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.

In July 2014, a coalition of twenty-one states, including Indiana, filed a petition with the U.S. Supreme Court seeking review of the decision of the appellate court that found the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants' impact on public health. On June 29, 2015, the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA's failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule back to the appellate court for further proceedings consistent with the opinion. In April 2016, in response to the Court's remand, the EPA affirmed its earlier conclusion in a Supplemental Finding. MATS compliance was required to commence April 16, 2015, and the Company continues to operate in full compliance with the MATS rule.

Notice of Violation for A.B. Brown Power Plant
The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. While the Company did not agree with the notice, it reached a final settlement with the EPA to resolve the NOV in December 2015.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company's request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to MATS effective in 2015 and to address the outstanding NOV. The total investment is estimated to be between $70 million and $75 million, roughly half of which has been spent to control mercury in both air and water emissions, and the remaining investment has been made to address the issues raised in the NOV.

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 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 (approximately $35 million) but remanded the case back to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the equipment required for the resolution of the NOV. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order. The basis for the appeal will not be known until the appeal brief is filed later this year. The Company believes the IURC decision is well founded and will ultimately be upheld.

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 with 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. The EPA is expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2018 based upon monitoring data from 2014-2016. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus could have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In December of 2015, the EPA proposed a supplement to the current Cross State Air Pollution Rule (CSAPR) that would require further NOx reductions during the ozone season (May - September). The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS
On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between the state 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 the state of Indiana on voluntary measures that the Company was able to implement without significant incremental costs to ensure that 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.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule
In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company’s generating plants will continue to be reused. As it relates to the CCR rule, legislation is currently being considered by Congress that would provide for enforcement of the federal program by states rather than through citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings.

Under the final 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 have not been 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. The Company is in the process of preparing site specific estimates, using engineering analyses and alternative methods of closure. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. The ongoing analysis and the refinement of assumptions may result in estimated costs that could be in excess of the current range of $35 million to $80 million.

At September 30, 2015, the Company recorded an approximate $25 million asset retirement obligation (ARO) and that amount is unchanged at June 30, 2016. The recorded ARO reflected the present value of the approximate $35 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company anticipates spending approximately $12 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELGs)
Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology- based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence within the 2018-2023 time frame. Current wastewater discharge permits for the Brown and Culley power plants expire in October and December 2016, respectively. The Company is working with Indiana regulators on permit renewals which will include a compliance schedule for ELGs. In no event will compliance with the ELGs be required prior to November 2018. The ELGs work in tandem with the recently released 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.

Cooling Water Intake Structures
Section 316(b) of the Clean Water Act requires that 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 a state level 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 2020-2021. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million.

Climate Change

On August 3, 2015, the EPA released its final Clean Power Plan (CPP) rule which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb $CO_2$/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the deadline of September 2016 to submit a final state implementation plan (SIP). Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb $CO_2$/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015 and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January of 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 with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted a stay to delay the regulation while being challenged in court. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the September 2016 deadline and could extend implementation to 2024.

In the event that a state does not submit a SIP, the EPA also released a proposed federal implementation plan (FIP), which would be imposed on those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on generating units. Under the proposed FIP, the $CO_2$ emission rate limit for coal-fired units would start at 1,671 lbs $CO_2$/MWh in 2022 and decrease to a final emission rate cap of 1,305 lbs $CO_2$/MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent than the state reduction goal for Indiana, the cap would apply directly to generating units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as would be available in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. The FIP will be subject to extensive public comments prior to finalization. Whether Indiana will file a SIP has yet to be determined. Pending that determination, the electric utilities in Indiana will continue to encourage the state's designated agency to analyze various compliance options and the possible integration into a state plan submittal.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of $CO_2$ produced from electric generation. The Company’s share of total tons of $CO_2$ generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005, the Company has achieved a reduction in emissions of $CO_2$ of 31 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. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of $CO_2$ can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and landfill gas investment. With respect to $CO_2$ emission rate, since 2005 the Company has lowered its $CO_2$ emission rate (as measured in lbs $CO_2$/MWh) from 1,967 lbs $CO_2$/MWh to 1,922 lbs $CO_2$/MWh, for a reduction of 3 percent. The Company’s $CO_2$ emission rate of 1,922 lbs $CO_2$/MWh is basically the same as Indiana's average $CO_2$ emission rate of 1,923 lbs $CO_2$/MWh. The Company plans to consider these reductions in $CO_2$ emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown

At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and the proposed FIP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28% GHG emission reduction from 2005 levels by 2025. As previously noted, since 2005, the Company has achieved reduced emissions of $CO_2$ by 31 percent (on a tonnage basis). While the legislative outcome 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.

Integrated Resource Planning Process

As required by the state of Indiana, the Company is currently in the process of completing its 2016 Integrated Resource Plan (IRP). 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 will hold three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progresses. Two of the three public meetings were held in April and July. A final IRP report is expected to be submitted to the IURC for review in November 2016. While the IURC reviews these reports, it does not formally approve or reject the plans. In developing its IRP, the Company will consider 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. Due to the Company continuing to study compliance requirements and as the IRP will be used to drive future resource decisions, the Company cannot reasonably estimate the total cost it will incur to comply with the CCR, ELG, and CPP regulations.

Further, the 2016 IRP will also evaluate the ongoing operation of the 300 MW unit at the Warrick Power Plant (Warrick Unit 4) that SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own as tenants in common. SIGECO's proportionate cost of the unit is included in rate base. In the first quarter of 2016, Alcoa closed its smelter operations. Historically, on-site generation owned and operated by AGC has been used to provide power to the smelter, as well as other mill operations, which will continue. Generation from Alcoa's share of Warrick Unit 4 has historically been sold into the MISO market. Alcoa's operational changes, as described above, lead to a number of uncertainties including its plans regarding the future ownership and operation of Warrick Unit 4 as well as potential environmental regulation implications under the CCR and ELG regulations. The Company is actively working with Alcoa on plans related to continued operation of their generation and what operating scenarios to consider in the IRP.

The 2016 IRP will produce a variety of resource options to be considered, including a preferred resource plan. Based on the resulting analysis, the Company will develop an overall strategy that may include compliance projects on some units, possible replacement of other units, and the opportunity for the use of renewable sources. While the cost of compliance with CCR, ELG, and CPP could be significant, the Company anticipates compliance costs associated with ELG and CCR will likely be the most significant. The Company believes that all compliance costs would be considered a federally mandated cost of providing electricity, and therefore if incurred, should be recoverable either from customers through Senate Bill 251 as referenced above, Senate Bill 29, which was used by the Company to recover its initial pollution control investments as clean coal environmental expenditures, or through other forms of rate recovery.

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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 $14.8 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2016 and December 31, 2015, approximately $2.8 million and $3.3 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

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12. Impact of Recently Issued Accounting Principles

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that 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.

On July 9, 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016. The Company is currently evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. The guidance was adopted as of January 1, 2016 and has been applied retrospectively to all periods presented. The effect of the change on the December 31, 2015 balance sheet was the reclassification of $8.6 million from Regulatory assets to Long-term Debt and the reclassification of $1.3 million from Other assets to Long-term Debt. The reclassification had no material impact on the Company's financial condition, results of operations, or cash flows as a result of the adoption.

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.

Stock Compensation
In March 2016, the FASB issued new accounting guidance which is intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU is effective for annual periods beginning after December 15, 2016, and interim periods therein. Early application is permitted. The Company is currently evaluating the standard to determine the impact it will have on the financial statements, if any.

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.

13. Fair Value Measurements

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

| (In millions) | June 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Carrying Amount | Est. Fair Value | Carrying Amount | Est. Fair Value |
| Long-term debt | $1,713.5 | $1,902.3 | $1,785.9 | $1,899.6 |
| Short-term borrowings | 45.2 | 45.2 | 14.5 | 14.5 |
| Cash & cash equivalents | 15.9 | 15.9 | 74.7 | 74.7 |
| Restricted cash | 5.8 | 5.8 | 5.9 | 5.9 |

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

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

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

Because of the nature of certain other investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At June 30, 2016 and December 31, 2015, the fair value for these financial instruments was not estimated. The carrying value of these investments at June 30, 2016 and December 31, 2015 was approximately $16.1 million, and is included in Other nonutility investments.

The Company has reclassified its debt issuance costs, in accordance with ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. The adoption of the accounting standard update changes the presentation of debt issuance costs in financial statements by requiring an entity to present such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. The guidance was adopted as of January 1, 2016, and has been applied retrospectively to all periods presented. The effect of the change on the December 31, 2015 balance sheet was the reclassification of $8.6 million from Regulatory assets to Long-term Debt and the reclassification of $1.3 million from Other assets to Long-term Debt. The adoption of the standard had no material impact on the Company's financial condition, results of operations, or cash flows.

14. Segment Reporting

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

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

The Nonutility Group reports the following segments: Energy Services, Infrastructure Services, and Other Businesses. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. The Infrastructure Services segment through wholly owned subsidiaries Miller Pipeline, LLC and Minnesota Limited, LLC, provide underground pipeline construction and repair services for customers that include Vectren Utility Holdings' utilities. Fees incurred by Vectren Utility Holdings and its subsidiaries for these pipeline construction and repair services totaled $37.2 million and $31.6 million for the three months ended June 30, 2016 and 2015, respectively, and for the six months ended June 30, 2016 and 2015 totaled $56.8 million and $49.3 million, respectively.

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

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

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Revenues | | | | |
| Utility Group | | | | |
| Gas Utility Services | $132.0 | $128.6 | $413.1 | $481.5 |
| Electric Utility Services | 147.7 | 147.8 | 289.8 | 301.7 |
| Other Operations | 10.5 | 10.2 | 21.1 | 20.4 |
| Eliminations | (10.4) | (10.1) | (20.9) | (20.2) |
| Total Utility Group | 279.8 | 276.5 | 703.1 | 783.4 |
| Nonutility Group | | | | |
| Infrastructure Services | 189.2 | 231.4 | 301.7 | 408.3 |
| Energy Services | 65.9 | 43.7 | 115.3 | 66.8 |
| Total Nonutility Group | 255.1 | 275.1 | 417.0 | 475.1 |
| Corporate & Other Group | — | 0.2 | 0.1 | 0.4 |
| Eliminations | (1.2) | (0.8) | (1.8) | (1.7) |
| Consolidated Revenues | $533.7 | $551.0 | $1,118.4 | $1,257.2 |
| | | | | |
| Profitability Measure - Net Income (Loss) | | | | |
| Utility Group Net Income | | | | |
| Gas Utility Services | $4.7 | $3.4 | $45.1 | $43.8 |
| Electric Utility Services | 19.2 | 19.7 | 35.8 | 38.9 |
| Other Operations | 2.4 | 1.3 | 6.5 | 4.7 |
| Utility Group Net Income | 26.3 | 24.4 | 87.4 | 87.4 |
| Nonutility Group Net Income (Loss) | | | | |
| Infrastructure Services | 4.2 | 12.3 | (8.4) | 9.7 |

| | | | | |
|---|---|---|---|---|
| Energy Services | 2.3 | (0.4 ) | 2.5 | (3.5 ) |
| Other Businesses | — | (0.3 ) | (0.3 ) | (0.5 ) |
| Nonutility Group Net Income (Loss) | 6.5 | 11.6 | (6.2 ) | 5.7 |
| Corporate & Other Group Net Income (Loss) | (0.5 ) | (0.2 ) | (0.6 ) | (0.3 ) |
| Consolidated Net Income | $32.3 | $35.8 | $80.6 | $92.8 |

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

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

Indiana Gas provides energy delivery services to approximately 588,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 144,000 electric customers and approximately 111,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 318,000 natural gas customers located near Dayton in west central Ohio.

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

The Company has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company’s SEC filings. The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company’s 2015 annual report filed on Form 10-K.

### Executive Summary of Consolidated Results of Operations

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

The Utility Group generates revenue primarily from the delivery of natural gas and electric service to its customers. The primary source of cash flow for the Utility Group results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services. The Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. In addition to the Nonutility Group, as described above, there are other operations, referred to herein as Corporate and Other, that include unallocated corporate expenses such as advertising and certain charitable contributions, among other activities.

Results for the three months ended June 30, 2016 were earnings of $32.3 million, or $0.39 per share, compared to earnings of $35.8 million, or $0.43 per share for the three months ended June 30, 2015. For the six months ended June

30, 2016, consolidated net income was $80.6 million or $0.97 per share, compared to $92.8 million, or $1.12 per share for the six months ended June 30, 2015.

Consolidated Results

Net income (loss) and earnings per share, in total and by group, for the three and six months ended June 30, 2016 and 2015 follow:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (In millions, except per share data) | 2016 | 2015 | 2016 | 2015 |
| Net income (loss) | $32.3 | $35.8 | $80.6 | $92.8 |
| Attributed to: | | | | |
| Utility Group | 26.3 | 24.4 | 87.4 | 87.4 |
| Nonutility Group | 6.5 | 11.6 | (6.2 ) | 5.7 |
| Corporate & other | (0.5 ) | (0.2 ) | (0.6 ) | (0.3 ) |
| | | | | |
| Basic EPS | $0.39 | $0.43 | $0.97 | $1.12 |
| Attributed to: | | | | |
| Utility Group | 0.32 | 0.29 | 1.06 | 1.06 |
| Nonutility Group | 0.08 | 0.14 | (0.08 ) | 0.07 |
| Corporate & other | (0.01 ) | — | (0.01 ) | (0.01 ) |

Utility Group
In the second quarter of 2016, the Utility Group earnings were $26.3 million, compared to $24.4 million in 2015. In the six months ended June 30, 2016, the Utility Group earned $87.4 million, and was flat compared to 2015. Both the quarter and year to date periods reflect increases in gas utility margin from returns on the Indiana and Ohio infrastructure programs. This increase in the year to date period is partially offset by decreases in electric utility margin due to warmer weather in the first quarter of 2016 as compared to the significantly colder first quarter of 2015. Decreases in large customer usage in the year to date period, some of which is due to mild weather in the first quarter as compared to last year, also contributed to a decrease in both gas and electric utility margin year over year. Results in the year to date period reflect lower wholesale power margin due to lower market pricing compared to 2015. Results in both year to date and quarter to date periods were unfavorably impacted by higher performance-based compensation expense primarily driven by the increase in the Company's stock price. Operating expenses in the year to date period were also impacted by reduced power plant maintenance costs in 2016 compared to 2015.

Nonutility Group
The Nonutility group results for the second quarter of 2016 were earnings of $6.5 million, compared to earnings of $11.6 million in the prior year. For the six months ended June 30, 2016, the Nonutility Group reported a loss of $6.2 million, compared to earnings of $5.7 million in the prior year period. Results in 2016 are significantly lower than 2015 due to two large transmission station projects in early 2015 not repeated in 2016, lower margin on completed transmission work in 2016, and fewer projects being awarded in the first half of 2016, which is attributable to the increasingly competitive environment in the transmission business as other contractors continue to adjust crews and work load in the current lower oil price environment. Offsetting a portion of this decrease was an increase in earnings from Energy Services from increased revenues as well as the timing of federal tax deductions related to energy efficiency projects.

Dividends

Dividends declared for the three months ended June 30, 2016, were $0.40 per share, compared to $0.38 per share for the same period in 2015. Dividends declared for the six months ended June 30, 2016, were $0.80 per share, compared to $0.76 per share for the same period in 2015.

Use of Non-GAAP Performance Measures and Per Share Measures

Contribution to Vectren's Basic EPS
Per share earnings contributions of the Utility Group, Nonutility Group, and Corporate and Other are presented and are non-GAAP measures. Such per share amounts are based on the earnings contribution of each group included in the Company's

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

Detailed Discussion of Results of Operations

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

Results of Operations of the Utility Group

The Utility Group is comprised of Utility Holdings' operations, which consists of the Company's regulated utility operations and other operations that provide information technology and other support services to those regulated operations. Regulated operations consist of a natural gas distribution business and an electric transmission and distribution business. The natural gas distribution business provides natural gas distribution and transportation services to nearly two-thirds of Indiana and about 20 percent of Ohio, primarily in the west-central area. The electric transmission and distribution business provides electric distribution services primarily to southwestern Indiana, in addition to its power generating and wholesale power operations. In total, these regulated operations supply natural gas and/or electricity to over one million customers. Utility Group operating results before certain intersegment eliminations and reclassifications for the three and six months ended June 30, 2016 and 2015, follow:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (In millions, except per share data) | 2016 | 2015 | 2016 | 2015 |
| OPERATING REVENUES | | | | |
| Gas utility | $132.0 | $128.6 | $413.1 | $481.5 |
| Electric utility | 147.7 | 147.8 | 289.8 | 301.7 |
| Other | 0.1 | 0.1 | 0.2 | 0.2 |
| Total operating revenues | 279.8 | 276.5 | 703.1 | 783.4 |
| OPERATING EXPENSES | | | | |
| Cost of gas sold | 34.0 | 36.4 | 145.5 | 208.4 |
| Cost of fuel & purchased power | 45.2 | 47.0 | 89.4 | 97.0 |
| Other operating | 81.3 | 78.5 | 171.4 | 181.3 |
| Depreciation & amortization | 54.0 | 52.0 | 107.6 | 104.2 |
| Taxes other than income taxes | 13.1 | 12.1 | 30.2 | 31.2 |
| Total operating expenses | 227.6 | 226.0 | 544.1 | 622.1 |
| OPERATING INCOME | 52.2 | 50.5 | 159.0 | 161.3 |

| | | | | |
|---|---|---|---|---|
| OTHER INCOME - NET | 7.0 | 4.3 | 13.3 | 9.2 |
| INTEREST EXPENSE | 17.5 | 16.4 | 35.0 | 33.0 |
| INCOME BEFORE INCOME TAXES | 41.7 | 38.4 | 137.3 | 137.5 |
| INCOME TAXES | 15.4 | 14.0 | 49.9 | 50.1 |
| NET INCOME | $26.3 | $24.4 | $87.4 | $87.4 |
| | | | | |
| CONTRIBUTION TO VECTREN BASIC EPS | $0.32 | $0.29 | $1.06 | $1.06 |

Utility Group Margin

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

In addition, the Company separately reflects regulatory expense recovery mechanisms within Gas utility margin and Electric utility margin. These amounts generally represent dollar-for-dollar recovery of other operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. For example, demand side management and conservation expenses for both the gas and electric utilities; MISO administrative expenses for the Company's electric operations; uncollectible expense associated with the Company's Ohio gas customers; and recoveries of state mandated revenue taxes in both Indiana and Ohio are included in these amounts. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas Utility Margin

Gas Utility margin and throughput by customer type follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (In millions) | 2016 | 2015 | 2016 | 2015 |
| Gas utility revenues | $132.0 | $128.6 | $413.1 | $481.5 |
| Cost of gas sold | 34.0 | 36.4 | 145.5 | 208.4 |
| Total gas utility margin | $98.0 | $92.2 | $267.6 | $273.1 |
| Margin attributed to: | | | | |
| Residential & commercial customers | $75.3 | $69.7 | $205.2 | $196.0 |
| Industrial customers | 14.1 | 13.0 | 33.1 | 32.3 |
| Other | 1.5 | 2.5 | 4.3 | 5.9 |
| Regulatory expense recovery mechanisms | 7.1 | 7.0 | 25.0 | 38.9 |
| Total gas utility margin | $98.0 | $92.2 | $267.6 | $273.1 |
| Sold & transported volumes in MMDth attributed to: | | | | |
| Residential & commercial customers | 12.4 | 10.7 | 59.3 | 72.9 |
| Industrial customers | 29.9 | 28.3 | 65.8 | 66.3 |
| Total sold & transported volumes | 42.3 | 39.0 | 125.1 | 139.2 |

Gas utility margins were $98.0 million and $267.6 million for the three and six months ended June 30, 2016, and compared to 2015, increased $5.8 million quarter over quarter and decreased $5.5 million year over year. While rate designs substantially limit the impact of weather on small customer margin, the warmer weather in the first quarter of 2016 did decrease sold and transported volumes, resulting in lower year to date regulatory expense recovery margin and a corresponding decrease in operating expenses. In 2016 compared to 2015 year to date, excluding margin from regulatory expense recovery mechanisms which decreased $13.9 million, gas utility margin increased $8.4 million. Margin from regulatory expense recovery mechanisms was flat quarter over quarter in 2016 compared to 2015. Margin was favorably impacted by increased returns on infrastructure replacement programs in Indiana and Ohio of $5.3 million quarter over quarter and $10.2 million year to date compared to 2015. Partially offsetting this increase, customer margin from large and small customer usage decreased $1.1 million in 2016 compared to 2015 year to date, primarily due to warmer than normal weather in the first quarter.

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

| (In millions) | Three Months Ended June 30, 2016 | Three Months Ended June 30, 2015 | Six Months Ended June 30, 2016 | Six Months Ended June 30, 2015 |
|---|---|---|---|---|
| Electric utility revenues | $147.7 | $147.8 | $289.8 | $301.7 |
| Cost of fuel & purchased power | 45.2 | 47.0 | 89.4 | 97.0 |
| Total electric utility margin | $102.5 | $100.8 | $200.4 | $204.7 |
| Margin attributed to: | | | | |
| Residential & commercial customers | $63.6 | $62.8 | $123.5 | $126.5 |
| Industrial customers | 28.2 | 28.4 | 54.2 | 55.2 |
| Other | 0.8 | 0.5 | 2.1 | 1.5 |
| Regulatory expense recovery mechanisms | 3.0 | 1.9 | 7.1 | 5.3 |
| Subtotal: retail | $95.6 | $93.6 | $186.9 | $188.5 |
| Wholesale power & transmission system margin | 6.9 | 7.2 | 13.5 | 16.2 |
| Total electric utility margin | $102.5 | $100.8 | $200.4 | $204.7 |
| Electric volumes sold in GWh attributed to: | | | | |
| Residential & commercial customers | 652.9 | 643.1 | 1,292.6 | 1,345.7 |
| Industrial customers | 700.2 | 719.4 | 1,354.4 | 1,392.3 |
| Other customers | 5.3 | 4.8 | 11.4 | 10.9 |
| Total retail volumes sold | 1,358.4 | 1,367.3 | 2,658.4 | 2,748.9 |

Retail

Electric retail utility margins were $95.6 million and $186.9 million for the three and six months ended June 30, 2016, and compared to 2015, increased by $2.0 million in the quarter and decreased $1.6 million year to date. Electric results for the quarter, which are not protected by weather normalizing mechanisms, reflect a $0.6 million decrease in customer margin related to weather as annualized cooling degree days in the second quarter of 2016 were 104 percent of normal compared to 107 percent of normal in 2015. Similarly for the year to date period, electric results were unfavorably impacted by weather, primarily in the first quarter 2016, and resulted in a year to date decrease of $4.2 million in small customer margin year over year. Additionally, results reflect a decrease in large customer usage largely driven by less production as a result of customer plant shut downs for maintenance during the period. These decreases were somewhat offset by an increase in small customer usage of $1.1 million quarter over quarter and $0.6 million year to date compared to 2015. Margin from regulatory expense recovery mechanisms increased $1.1 million quarter over quarter and increased $1.8 million year to date compared to 2015, driven primarily by a corresponding increase in operating expenses associated with the electric efficiency programs.

On December 3, 2013, SABIC Innovative Plastics (SABIC), a large industrial utility customer of the Company, announced its plans to build a cogeneration (cogen) facility to be operational at the end of 2016 or early in 2017, in order to generate power to meet a significant portion of its ongoing power needs. Electric service was provided to SABIC by the Company under a long-term contract that expired on May 2, 2016. At that date, SABIC became a tariff customer. The cogen facility is expected to provide approximately 85 MW of capacity. The Company will continue to provide all of SABIC's power requirements above the approximate 85 MW capacity of the cogen. Once the cogen is operational, backup power will be provided under approved tariff rates.

Margin from Wholesale Electric Activities

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of MISO’s regional transmission expansion plans and also markets and sells its generating and transmission capacity to optimize the return on its owned assets.  Substantially all off-system sales are generated in the

MISO Day Ahead and Real Time markets when sales into the MISO in a given hour are greater than amounts purchased for native load. Further detail of MISO off-system margin and transmission system margin follows:

| (In millions) | Three Months Ended June 30, 2016 | 2015 | Six Months Ended June 30, 2016 | 2015 |
|---|---|---|---|---|
| MISO Transmission system margin | $6.2 | $6.4 | $11.8 | $12.9 |
| MISO Off-system margin | 0.7 | 0.8 | 1.7 | 3.3 |
| Total wholesale margin | $6.9 | $7.2 | $13.5 | $16.2 |

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms and other transmission system operations, totaled $6.2 million and $6.4 million during the three months ended June 30, 2016 and 2015, respectively. Transmission system margin was $11.8 million and $12.9 million during the six months ended June 30, 2016 and 2015, respectively. As of June 30, 2016, the Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $138.5 million at June 30, 2016. 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. Although the allowed return is currently being challenged as discussed below in Rate and Regulatory Matters, once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance. The Company has established a reserve pending the outcome of these complaints. Operating expenses are also recovered. The 345 kV project is the largest of these qualifying projects, with a cost of $106.8 million that earned the FERC approved equity rate of return, including while under construction. The last segment of that project was placed into service in December 2012.

In the second quarter of 2016, margin from off system sales was $0.7 million compared to $0.8 million in 2015. For the six months ended June 30, 2016, margin from off-system sales was $1.7 million compared to $3.3 million in 2015. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year is shared equally with customers. Results for the periods presented reflect lower market pricing due primarily to low natural gas prices, net of sharing.

Utility Group Operating Expenses

Other Operating

During the second quarter of 2016, other operating expenses were $81.3 million, an increase of $2.8 million, compared to the second quarter of 2015. For the six months ended June 30, 2016, other operating expenses were $171.4 million, a decrease of $9.9 million, compared to 2015. Excluding costs that are recovered directly in margin, other operating expenses increased $1.4 million quarter over quarter and decreased $1.4 million in the year to date period when compared to 2015. Both quarter and year to date periods reflect increases in performance-based compensation driven by an increase in the Company's stock price. In the year to date period, this increase was offset by decreases in costs driven primarily by the timing of power plant maintenance costs and lower energy delivery expenses due to the colder weather in 2015.

Depreciation & Amortization

In the second quarter of 2016, depreciation and amortization expense was $54.0 million, compared to $52.0 million in 2015. For the six months ended June 30, 2016, depreciation and amortization expense was $107.6 million, which represents an increase of $3.4 million compared to 2015. The increase reflects increased plant placed in service, which is largely driven by increased gas utility plant as a result of the Indiana and Ohio infrastructure programs.

Taxes Other Than Income Taxes

Taxes other than income taxes were $13.1 million for the second quarter of 2016, an increase of $1.0 million, compared to 2015. Year to date, taxes other than income taxes were $30.2 million compared to $31.2 million for the year to date period in 2015. The fluctuations are primarily due to changes in gas costs and thus fluctuations in revenues and related revenue taxes.

Other Income - Net

Other income-net reflects income of $7.0 million for the second quarter of 2016, an increase of $2.7 million, compared to 2015. Year to date, other income-net reflects income of $13.3 million, compared to $9.2 million in 2015. The increases are primarily due to increased allowance for funds used during construction (AFUDC) driven by increased capital expenditures related to gas utility infrastructure replacement investments.

Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
The Company monitors and maintains its natural gas distribution system to ensure natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in programs to replace bare steel and cast iron infrastructure and other activities in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations, many of which are a 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.

In April 2011, Indiana Senate Bill 251 (Senate Bill 251) was signed into Indiana law. The law 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, 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.

In April 2013, Indiana Senate Bill 560 (Senate Bill 560) was signed into Indiana law. This legislation 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 that, 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 and recovered 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.

In June 2011, Ohio House Bill 95 (House Bill 95) was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas utility to apply for recovery of much of its capital expenditure program. The 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 Condensed 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 June 30, 2016 and December 31, 2015, the Company has regulatory assets totaling $21.2 million and $19.9 million, respectively, associated with the deferral of depreciation and debt-related post-in-service carrying cost activities. Beginning in 2014, all bare steel and cast iron replacement activities are now part of the Company's seven-year capital

investment plan discussed further below.

Requests for Recovery under Indiana Regulatory Mechanisms
On August 27, 2014, the IURC issued an Order (August 2014 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 via a fixed monthly charge per residential customer.

Subsequent to the August 2014 Order, the Company filed and received Orders on each of its semi-annual updates, which recover in rates investments associated with the approved programs. In October 2015, the Company submitted its third semi-annual filing, seeking approval of the recovery in rates of investments made through June 30, 2015, and updates to the approved seven-year capital investment plan. On March 30, 2016, the IURC issued an Order (March 2016 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 projects were not approved for recovery through the mechanisms pursuant to these filings. Specifically, one project totaling about $65 million involving a 20-mile transmission line and other related investments required to support industrial customer growth and ongoing system reliability in the Lafayette, Indiana area 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 this law. In the March 2016 Order, the IURC did pre-approve the project for rate base inclusion upon the filing of the next base rate case. The Company believes that such plan updates should be expected to accommodate new projects that emerge during the term of the plan as ongoing risk assessments determine that new projects are required. The Company filed an appeal of the March 2016 Order on April 29, 2016 to challenge the IURC's finding which limits the scope of the Plan updates. The outcome of the appeal is expected in 2017.

On June 29, 2016, the IURC issued an Order (June 2016 Order) approving the inclusion in rates of investments made from July 2015 to December 2015. Through the June 2016 Order, approximately $262 million of the Plan's $890 million total has been spent and included for recovery as of December 31, 2015.

At June 30, 2016 and December 31, 2015, the Company has regulatory assets related to the Plan totaling $46.7 million and $28.6 million, respectively, associated with the return on investment as well as the deferral of depreciation and other operating expenses.

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 and certain other infrastructure. 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. Due to the expiration of the initial five-year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. 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 over the next five years. 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; however, the remaining capital expenditure plan, estimated to be approximately $90 million for the remainder of 2016 and 2017, is not expected to exceed those caps. 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 under the DRR totaling $220.7 million as of June 30, 2016. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $21.3 million and $18.2 million at June 30, 2016 and December 31, 2015, respectively. On May 2, 2016, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2015. A procedural schedule has been set in this proceeding and the Company expects an order by September 2016.

Given the extension of the DRR through 2017, as discussed above, and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will not file a general rate case for the inclusion in rate base of the above costs until the expiration of the DRR. As such, the bill impact limits discussed below are not expected to be reached given the Company's capital expenditure plan during the remaining two-year time frame.

The PUCO has also issued Orders approving the Company's filings under Ohio House Bill 95. These Orders approve deferral of the Company’s Ohio capital expenditure program for items not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. Ohio House Bill 95 Orders also have 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. As of June 30, 2016, the Company's deferrals have not reached this bill impact cap. On May 2, 2016, 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 2016.

Pipeline and Hazardous Materials Safety Administration (PHMSA)
On March 18, 2016, PHMSA published a notice of proposed rulemaking (NPRM) on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements from the 2011 Pipeline Safety Act and sets out more stringent requirements than anticipated. The Company is evaluating the impact the proposed rules would have on the Company's transmission integrity management program and the design, construction, and repair of transmission pipeline assets, including the potential for additional capital expenditures and increase in operation and maintenance expense. The Company believes that such compliance costs would be considered federally mandated costs and therefore should be recoverable from customers using the regulatory recovery mechanisms referenced above.

Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing
On January 28, 2015, the IURC issued an Order (January 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) related to sulfur trioxide emissions from the EPA. As of June 30, 2016, approximately $31 million has been spent on equipment to control mercury in both air and water emissions, and $37 million to address the issues raised in the NOV. The total investment is estimated to be between $70 million and $75 million. The Order approved the Company’s request for deferred accounting treatment, as supported by provisions under Indiana Senate Bill 29 (Senate Bill 29) and Senate Bill 251. The accounting treatment includes the deferral of depreciation and property tax expense related to these investments, accrual of post-in-service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The initial phase of the projects went into service in 2014, with the remaining investment occurring in 2015 and 2016. As of June 30, 2016, the Company has approximately $4.6 million deferred related to depreciation, property tax, and operating expense, and $1.9 million deferred related to post-in-service carrying costs.

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 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 (approximately $35 million) but remanded the case back to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the NOV-required equipment. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order. The basis for the appeal will not be known until the appeal brief is filed later this year. The

Company believes the IURC decision is well founded and will ultimately be upheld.

SIGECO Electric Demand Side Management (DSM) Program Filing

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

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performance incentive mechanism based on measured savings related to certain DSM programs; and 3) lost margin recovery associated with the implementation of DSM programs for large customers. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. For the six months ended June 30, 2016 and 2015, the Company recognized electric utility revenue of $5.4 million and $4.8 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Indiana Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that had been conducted to meet the energy savings requirements established by the IURC in 2009. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of January 1, 2015, approximately 80 percent of the Company’s eligible industrial load has opted out of participation in the applicable energy efficiency programs. The Company filed a request for IURC approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the IURC issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015, and new programs for 2015 were implemented during the first quarter of 2015.

On May 6, 2015, Indiana's governor signed Indiana Senate Bill 412 (Senate Bill 412) into law requiring electricity suppliers to submit energy efficiency plans to the IURC at least once every three years. Senate Bill 412 also permits 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. In September 2015, the Company received an Order to continue offering and recovering the associated cost of its 2015 programs until March 31, 2016. In October 2015, the OUCC and Citizens Action Coalition of Indiana filed testimony recommending the rejection of the Company’s plan, contending it was not reasonable under the terms of Senate Bill 412 due to the program design and the Company’s proposal to recover lost revenues and incentives associated with the measures. Vectren filed rebuttal testimony in October 2015 defending the plan’s compliance with Senate Bill 412.

On March 23, 2016, the IURC issued an Order approving the Company’s 2016-2017 energy efficiency programs. The Order provides for cost recovery of program and administrative expenses and includes performance incentives for reaching energy savings goals. The Order also included a lost margin recovery mechanism that now limits that 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 follows three other recent IURC decisions implementing the same lost margin recovery limitation with respect to other electric utilities in Indiana. The Company is committed to continuing to promote and drive participation in its 2016-2017 energy efficiency programs and beyond and has therefore appealed this lost margin recovery restriction.

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. The joint parties seek to reduce the 12.38 percent ROE used in the MISO transmission owners’ rates, including SIGECO’s formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. A second customer complaint case was filed on February 11, 2015 as the maximum FERC-allowed refund period for the November 12, 2013 case ended February 11, 2015. This second complaint covers the period February 12, 2015 through May 11, 2016. As of June 30, 2016, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $138.5 million at June 30, 2016.

These joint complaints are similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving a 10.57 percent return on equity and a new calculation methodology. The new methodology is based on a two-step discounted cash flow analysis that uses short-term and long-term growth projections in calculating ROE rates for a proxy group of electric utilities. The FERC has stated that it expects future decisions on pending complaints related to similar ROE issues to be guided by the New England transmission decision.

The FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable but denied the portion of the complaint addressing the equity component of the capital structure. An initial decision from its administrative law judge was received on December 22, 2015, authorizing the transmission owners to collect a Base ROE of 10.32 percent from November 12, 2013 through February 11, 2015 (the “first refund period”). The FERC is expected to rule on the proposed order in late 2016. An initial decision from the FERC administrative law judge in the second complaint case was received on June 30, 2016, authorizing the transmission owners to collect a Base ROE of 9.70 percent from February 12, 2015 through May 11, 2016 (the “second refund period”). The FERC is expected to rule on the proposed order in the second complaint case in 2017.

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 FERC deferred the implementation of this adder until the pending complaint is resolved. Once the FERC sets a new ROE in the complaint case, this adder will be applied to that ROE, with retroactive billing to occur back to January 7, 2015.

The Company has established a reserve considering the initial decisions and the approved 50 basis points adder.

Environmental Matters

The Company's utility operations and properties are 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.

With the trend toward stricter standards, greater regulation, and more extensive permit requirements, the Company's investment in compliant infrastructure, and the associated operating costs have increased and are expected to increase in the future. 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.

Air Quality

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the utility MATS rule. 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.

In July 2014, a coalition of twenty-one states, including Indiana, filed a petition with the U.S. Supreme Court seeking review of the decision of the appellate court that found the EPA appropriately based its decision to list coal and oil fired generation units as a source of the pollutants at issue solely on those pollutants’ impact on public health. On June 29, 2015, the U.S. Supreme Court reversed the appellate court decision on the basis of the EPA’s failure to consider costs before determining whether it was appropriate and necessary to regulate steam electric generating units under Section 112 of the Clean Air Act. The Court did not vacate the rule, but remanded the MATS rule back to the appellate court for further proceedings consistent with the opinion. In April 2016, in response to the Court's remand, the EPA affirmed its earlier conclusion in a Supplemental Finding. MATS compliance was required to commence April 16, 2015, and the Company continues to operate in full compliance with the MATS rule.

Notice of Violation for A.B. Brown Power Plant

The Company received a NOV from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts when the facility was equipped with Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. While the Company did not agree with the notice, it reached a final settlement with the EPA to resolve the NOV in December 2015.

As noted previously, on January 28, 2015, the IURC issued an Order approving the Company’s request for approval of capital investments on its coal-fired generation units to comply with new EPA mandates related to MATS effective in 2015 and to address the outstanding NOV. The total investment is estimated to be between $70 million and $75 million, roughly half of which has been spent to control mercury in both air and water emissions, and the remaining investment has been made to address the issues raised in the NOV.

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 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 (approximately $35 million) but remanded the case back to the IURC to determine whether a certificate of public convenience and necessity (CPCN) should be issued for the equipment required by the NOV (approximately $40 million). On June 22, 2016, the IURC issued an Order granting Vectren a CPCN for the equipment required for the resolution of the NOV. On July 21, 2016, the appellants initiated an appeal of the IURC's June 22, 2016 Order. The basis for the appeal will not be known until the appeal brief is filed later this year. The Company believes the IURC decision is well founded and will ultimately be upheld.

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 with 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. The EPA is expected to make final determinations as to whether a region is in attainment for the new NAAQS in 2018 based upon monitoring data from 2014-2016. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus could have an effect on future economic development activities in the Company's service territory, the Company does not anticipate any significant compliance cost impacts from the determination given its previous investment in SCR technology for NOx control on its units. In December of 2015, the EPA proposed a supplement to the current Cross State Air Pollution Rule (CSAPR) that would require further NOx reductions during the ozone season (May - September). The Company is positioned to comply with these NOx reduction requirements through its current investment in SCR technology.

One Hour SO2 NAAQS

On February 16, 2016, the EPA notified states of the commencement of a 120 day consultation period between the state 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 the state of Indiana on voluntary measures that the Company was able to implement without significant incremental costs to ensure that 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.

Coal Ash Waste Disposal, Ash Ponds and Water

Coal Combustion Residuals Rule

In December 2014, the EPA released its final Coal Combustion Residuals (CCR) rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). On April 17, 2015, the final rule was published in the Federal Register. The final rule allows beneficial reuse of ash and the majority of the ash generated by the Company's generating plants will continue to be reused. As it relates to the CCR rule, legislation is currently being considered by Congress that would provide for enforcement of the federal program by states rather than through citizen suits. Additionally, the CCR rule is currently being challenged by multiple parties in judicial review proceedings.

Under the final 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 have not been 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. The Company is in the process of preparing site specific estimates, using engineering analyses and alternative methods of closure. Significant factors impacting the resulting cost estimates include the closure time frame and the method of closure. The ongoing analysis and the refinement of assumptions may result in estimated costs that could be in excess of the current range of $35 million to $80 million.

At September 30, 2015, the Company recorded an approximate $25 million asset retirement obligation (ARO) and that amount is unchanged at June 30, 2016. The recorded ARO reflected the present value of the approximate $35 million in estimated costs in the range above. These assumptions and estimations are subject to change in the future and could materially impact the amount of the estimated ARO.

In order to maintain current operations of the ponds, the Company anticipates spending approximately $12 million on the reinforcement of the ash pond dams and other operational changes in 2016 to meet the more stringent 2,500 year seismic event structural and safety standard in the CCR rule.

Effluent Limitation Guidelines (ELGs)

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. On September 30, 2015, the EPA released final revisions to the existing steam electric ELGs setting stringent technology- based water discharge limits for the electric power industry. The EPA focused this rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations, specifically setting strict water discharge limits for arsenic, mercury and selenium for scrubber waste waters. The ELGs will be implemented when existing water discharge permits for the plants are renewed, with compliance activities expected to commence within the 2018-2023 time frame. Current wastewater discharge permits for the Brown and Culley power plants expire in October and December 2016, respectively. The Company is working with Indiana regulators on permit renewals which will include a compliance schedule for ELGs. In no event will compliance with the ELGs be required prior to November 2018. The ELGs work in tandem with the recently released 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.

Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires that 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 a state level 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 2020-2021. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million.

Climate Change

Vectren is committed to responsible environmental stewardship and conservation efforts, and if a national climate change policy is implemented, believes it should have the following elements:

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

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

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company's direct CO2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA's e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions

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

- Since 2005, the Company has achieved a reduction in emissions of CO2 of 31 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.
- Focusing the Company's mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs. Vectren's annual sustainability report received C level certification by the Global Reporting Initiative. This certification creates shared value, demonstrates the Company's commitment to sustainability and denotes transparency in operations;
- 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;
- Reducing the Company's carbon footprint by measures such as utilizing hybrid vehicles and optimizing generation efficiencies by utilizing dense pack technology;
- Reducing methane emissions through becoming a founding partner in the EPA Natural Gas STAR Methane Challenge Program. The Company's primary method for reducing methane emissions is through continued replacement of bare steel and cast iron gas distribution pipeline assets;
- Developing renewable energy and energy efficiency performance contracting projects through its Energy Services segment; and
- Helping energy producers install pipes that allow for more natural gas power generation and reduce gas flaring through its Infrastructure Services segment.

On August 3, 2015, the EPA released its final Clean Power Plan (CPP) rule which requires a 32 percent reduction in carbon emissions from 2005 levels. This results in a final emission rate goal for Indiana of 1,242 lb CO2/MWh to be achieved by 2030. The new rule gives states the option of seeking a two-year extension from the deadline of September 2016 to submit a final state implementation plan (SIP). Under the CPP, states have the flexibility to include energy efficiency and other measures should they choose to implement a SIP as provided in the final rule. While states are given an interim goal (1,451 lb $CO_2$/MWh for Indiana), the final rule gives states the flexibility to shape their own emissions reduction over the 2022-2029 time period. The final rule was published in the Federal Register on October 23, 2015 and that action was immediately followed by litigation initiated by Indiana and 23 other states as a coalition challenging the rule. In January of 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 with the U.S. Supreme Court. On February 9, 2016, the U.S. Supreme Court granted a stay to delay the regulation while being challenged in court. The stay will remain in place while the lower court concludes its review. Among other things, the stay delays the requirement to submit a final SIP by the September 2016 deadline and could extend implementation to 2024.

In the event that a state does not submit a SIP, the EPA also released a proposed federal implementation plan (FIP), which would be imposed on those states without an approved SIP. The proposed FIP would apply an emission rate requirement directly on generating units. Under the proposed FIP, the CO2 emission rate limit for coal-fired units would start at 1,671 lbs CO2/MWh in 2022 and decrease to a final emission rate cap of 1,305 lbs CO2/MWh by 2030. While the FIP emission rate cap appears to be slightly less stringent than the state reduction goal for Indiana, the cap would apply directly to generating units and these units would not have the benefit of averaging emission rates with rates from zero-carbon sources as would be available in a SIP. Purchases of emission credits from zero-carbon sources can be made for compliance. The FIP will be subject to extensive public comments prior to finalization. Whether Indiana will file a SIP has yet to be determined. Pending that determination, the electric utilities in Indiana will continue to encourage the state's designated agency to analyze various compliance options and the possible integration into a state plan submittal.

At the time of release of the CPP, Indiana was the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. The Company’s share of total tons of CO2 generated by Indiana's electric utilities has historically been less than 6 percent. Since 2005, the Company has achieved a reduction in emissions of CO2 of 31 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. Since emissions are further impacted by coal burn reductions and energy efficiency programs, the Company's emissions of CO2 can vary year to year. With respect to renewable generation, in 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 4 percent of its electricity being provided by energy sources other than coal and natural gas, due to the long-term wind contracts and landfill gas investment. With respect to CO2 emission rate, since 2005 the Company has lowered its CO2 emission rate (as measured in lbs CO2/MWh) from 1,967 lbs CO2/MWh to 1,922 lbs CO2/MWh, for a reduction of 3 percent. The Company’s CO2 emission rate of 1,922 lbs CO2/MWh is basically the same as Indiana's average CO2 emission rate of 1,923 lbs CO2/MWh. The Company plans to consider these reductions in CO2 emissions and renewable generation in future discussions with the state to develop a possible state implementation plan.

Impact of Legislative Actions & Other Initiatives is Unknown
At this time, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. The Company is undertaking a detailed review of the requirements of the CPP and the proposed FIP and a review of potential compliance options. The Company will also continue to remain engaged with the Indiana legislators and regulators to assess the final rule and to develop a plan that is the least cost to its customers.

In addition to the federal programs, the United States and 194 other countries agreed by consensus to limit GHG emissions beginning after 2020 in the 2015 United Nations Framework Convention on Climate Change Paris Agreement. The United States has proposed a 26-28% GHG emission reduction from 2005 levels by 2025. As previously noted, since 2005, the Company has achieved reduced emissions of CO2 by 31 percent (on a tonnage basis). While the legislative outcome 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.

Integrated Resource Planning Process

As required by the state of Indiana, the Company is currently in the process of completing its 2016 Integrated Resource Plan (IRP). 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 will hold three public stakeholder meetings to gather input and feedback as well as communicate results of the IRP process as it progresses. Two of the three public meetings were held in April and July. A final IRP report is expected to be submitted to the IURC for review in November 2016. While the IURC reviews these reports, it does not formally approve or reject the plans. In developing its IRP, the Company will consider 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. Due to the Company continuing to study compliance requirements and as the IRP will be used to drive future resource decisions, the Company cannot reasonably estimate the total cost it will incur to comply with the CCR, ELG, and CPP regulations.

Further, the 2016 IRP will also evaluate the ongoing operation of the 300 MW unit at the Warrick Power Plant (Warrick Unit 4) that SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of Alcoa, Inc. (Alcoa), own as tenants in common. SIGECO's proportionate cost of the unit is included in rate base. In the first quarter of 2016, Alcoa closed its smelter operations. Historically, on-site generation owned and operated by AGC has been used to provide power to the smelter, as well as other mill operations, which will continue. Generation from Alcoa's share of Warrick Unit 4 has historically been sold into the MISO market. Alcoa's operational changes, as described above, lead to a number of uncertainties including its plans regarding the future ownership and operation of Warrick Unit 4 as well as potential environmental regulation implications under the CCR and ELG regulations. The Company is actively working with Alcoa on plans related to continued operation of their generation and what operating scenarios to consider in the IRP.

The 2016 IRP will produce a variety of resource options to be considered, including a preferred resource plan. Based on the resulting analysis, the Company will develop an overall strategy that may include compliance projects on some units, possible replacement of other units, and the opportunity for the use of renewable sources. While the cost of compliance with CCR, ELG, and CPP could be significant, the Company anticipates compliance costs associated with ELG and CCR will likely be the most significant. The Company believes that all compliance costs would be considered a federally mandated cost of providing electricity, and therefore if incurred, should be recoverable either from customers through Senate Bill 251 as referenced above, Senate Bill 29, which was used by the Company to recover its initial pollution control investments as clean coal environmental expenditures, or through other forms of rate recovery.

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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 $14.8 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of June 30, 2016 and December 31, 2015, approximately $2.8 million and $3.3 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Results of Operations of the Nonutility Group

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

The Nonutility Group results were earnings of $6.5 million and a loss of $6.2 million for the three and six months ended June 30, 2016, respectively, compared to earnings of $11.6 million and $5.7 million for the three and six months ended June 30, 2015.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (In millions, except per share amounts) | 2016 | 2015 | 2016 | 2015 |
| NET INCOME (LOSS) | $6.5 | $11.6 | $(6.2) | $5.7 |
| CONTRIBUTION TO VECTREN BASIC EPS | $0.08 | $0.14 | $(0.08) | $0.07 |
| NET INCOME (LOSS) ATTRIBUTED TO: | | | | |
| Infrastructure Services | $4.2 | $12.3 | $(8.4) | $9.7 |
| Energy Services | 2.3 | (0.4) | 2.5 | (3.5) |
| Other Businesses | — | (0.3) | (0.3) | (0.5) |

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly owned subsidiaries Miller Pipeline, LLC (Miller or Miller Pipeline) and Minnesota Limited, LLC (Minnesota Limited). Inclusive of holding company costs, results for Infrastructure Services' operations for the second quarter of 2016 were earnings of $4.2 million, compared to earnings of $12.3 million for the same period in the prior year. During the six months ended June 30, 2016, Infrastructure Services operated at a loss of $8.4 million, compared to earnings of $9.7 million year to date in 2015.

The distribution portion of the infrastructure operation is performing well as gas utilities across the country continue to make significant investments in their gas infrastructure systems. The growth trend in the distribution services business is expected to continue as utilities expand their infrastructure replacement programs. The lower results from the transmission portion of the business are due largely to two large station projects completed in the first quarter of 2015 and lower margin on awarded transmission contracts, as well as fewer transmission maintenance projects being awarded in 2016. The lower margin on projects, coupled with a reduction in the projects awarded, is reflective of a very competitive environment as other contractors continue to adjust crews and workload as some large gas and oil projects have been delayed due to the lengthening environmental and regulatory approval process and the current low oil price environment. Those contractors continue to compete aggressively in the repair and maintenance market, resulting in fewer projects awarded to Infrastructure Services and lower margins on projects won. Finally, even though the start date of some of the announced pipeline projects may be further delayed, primarily due to environmental or regulatory review, the fundamental business model related to the long cycle of repair and maintenance work in the transmission sector remains unchanged as the demand remains high due to aging infrastructure and evolving safety and reliability regulations. Total Infrastructure Services gross revenues for the year to date period were $301.7 million, compared to gross revenues of $408.3 million for the same period in 2015.

At June 30, 2016, Infrastructure Services had an estimated backlog of blanket contracts of $420 million and bid contracts of $275 million, for a total backlog of $695 million. That amount includes about $50 million, now in question, related to a project that is at significant risk of being canceled, announced just this week. More information is needed to determine whether any of that work, including some station work, may still be completed. This compares to an estimated backlog at March 31, 2016 of $440 million for blanket contracts and $215 million for bid contracts, for a total of $655 million. Total backlog at June 30, 2015 was $575 million.

The long-term outlook for construction activity remains strong as utilities, municipalities and pipeline operators repair and replace aging natural gas and oil pipelines and related infrastructure. The continued low oil prices have resulted in some production cuts that have been predominately related to the drilling of new wells. Even after taking into account the major project that is now at significant risk of being canceled, there are still significant new pipeline projects totaling approximately 13,000 miles announced for primarily 2016 through 2018 that, even if further delayed, are ultimately expected to absorb resources and equipment. The result should be a gradual increase in opportunities for pipeline maintenance work and some increase in margins as the competition for maintenance work decreases. Further, evolving safety and reliability regulations are anticipated to continue to drive demand in maintenance and integrity work. On March 18, 2016, PHMSA published a notice of proposed rulemaking on the safety of gas transmission and gathering lines. The proposed rule addresses many of the remaining requirements from the 2011 Pipeline Safety Act and will likely lead to additional demand for pipeline maintenance and integrity work. In addition, pipelines are still being built for producing wells and, as such, the demand for this work too is still strong.

In 2016, the estimated depreciable lives for certain pieces of equipment at Minnesota Limited, LLC were reevaluated and extended due to a change in service life of the equipment. As a result of this evaluation, the Company extended the estimated useful life of certain pieces of equipment effective January 1 of the current year. The effect of this change in estimate is an anticipated reduction of annual depreciation expense of approximately $9.6 million in 2016 but is not expected to have a material impact on net income as these costs are fully reflected in bids as costs to recover.

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects through its wholly owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' operations were earnings of $2.3 million during the second quarter of 2016, compared to a loss of $0.4 million during the second quarter of 2015. For the six months ended June 30, 2016, earnings were $2.5 million, compared to a loss of $3.5 million in 2015. Energy Services has record year to date revenues of $115.3 million in 2016, compared to revenues of $66.8 million for the year to date period in 2015.

At June 30, 2016, the backlog of signed fixed price contracts remains high at $187 million. The backlog at June 30, 2016 is down compared to December 31, 2015 due to the significant number of contracts signed in the fourth quarter of 2015 as well as the amount of backlog converted to revenue in the first two quarters of 2016. However, the sales funnel at June 30, 2016, is now at a record high level of $435 million. The Company's long-term view of the performance contracting and sustainable infrastructure opportunities remains strong as the national focus on energy conservation and security, renewable energy, and sustainability continues to grow given the expected rise in power prices across the country and customer focus on efficiency and clean energy. Expected activity in the federal sector, as well as positive indications in the public sector and sustainable infrastructure business, is reflected in the strong backlog and sales funnel. Consistent with the national focus on energy conservation and efficiency, in December 2015, the tax code section (Section 179D) allowing for federal tax deductions related to energy efficiency savings achieved was retroactively extended for 2015 through 2016. The impact of these tax deductions, net of consulting fees, reflected in second quarter 2016 results was $0.7 million and $1.4 million year to date. Given the timing of the extension in 2015, there was no impact in the 2015 comparative periods' results.

Impact of Recently Issued Accounting Guidance

Revenue Recognition Guidance
In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP. The amendments in this guidance state that 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.

On July 9, 2015, the FASB approved a one year deferral that became effective through an ASU in August and changed the effective date to annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted, but not before the original effective date of December 15, 2016. The Company is currently evaluating the standard to determine application date, transition method, and impact the standard will have on the financial statements.

Simplifying the Presentation of Debt Issuance Costs
In April 2015, the FASB issued new accounting guidance on accounting for debt issuance costs which changes the presentation of debt issuance costs in financial statements. This ASU requires an entity to present such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs will continue to be reported as interest expense. This ASU is effective for annual reporting periods beginning after December 15, 2015. The guidance was adopted as of January 1, 2016 and has been applied retrospectively to all periods presented. The effect of the change on the December 31, 2015 balance sheet was the reclassification of $8.6 million from Regulatory assets to Long-term Debt and the reclassification of $1.3 million from Other assets to Long-term Debt. The reclassification had no material impact on the Company's financial condition, results of operations, or cash flows as a result of the adoption.

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.

Stock Compensation
In March 2016, the FASB issued new accounting guidance which is intended to simplify several aspects of accounting for share-based payment transactions, including the income tax consequences. This ASU is effective for annual periods beginning after December 15, 2016, and interim periods therein. Early application is permitted. The Company is currently evaluating the standard to determine the impact it will have on the financial statements, if any.

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

Financial Condition

Within the Company's consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital's debt, but does not guarantee Utility Holdings' debt. Vectren Capital's long-term debt, including current maturities, and short term obligations outstanding at June 30, 2016 approximated $334 million and $6 million, respectively. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities SIGECO, Indiana Gas, and VEDO. Utility Holdings' long-term debt, including current maturities, outstanding at June 30, 2016 approximated $995 million. As of June 30, 2016, Utility Holdings had $39 million short-term borrowings outstanding. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue new tax-exempt debt to fund qualifying pollution control capital expenditures.  Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at June 30, 2016, was approximately $384 million.

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

Vectren Corporation's corporate credit rating is A-, as rated by Standard and Poor's Ratings Services (Standard and Poor's). Moody's Investor Services (Moody's) does not provide a rating for Vectren Corporation. The credit ratings of the senior unsecured debt of Utility Holdings, SIGECO and Indiana Gas, at June 30, 2016, are A-/A2, as rated by Standard and Poor's and Moody's, respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings' commercial paper has a credit rating of A-2/P-1. The current outlook of both 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 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 50 percent and 49 percent of long-term capitalization at June 30, 2016 and December 31, 2015, 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 June 30, 2016 the Company is 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 cash flow generated from nonutility businesses. However, it has considered access to both short-term and long-term capital markets as a significant source of funding for capital requirements as the resources required for capital investment remain uncertain for a variety of factors including expanded environmental regulations, growth of the regulated business, and growth of Infrastructure Services and Energy Services. These regulations may result in the need to raise additional capital in the coming years. To the extent that events beyond the Company's control create uncertainty in capital markets, cost of capital and ability to access capital markets may be affected.

Utility Holdings routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. While the Company has no plans to issue any long-term financing at the utility level, this authority allows for the flexibility for each utility to issue debt and equity securities to third parties or to issue debt and equity securities to Utility Holdings and thus receive some of the proceeds from various Utility Holdings issuances to third parties on the same terms as those obtained by Utility Holdings. It is expected that the majority of the long-term debt needs of the utilities will be met through these debt issuances by Utility Holdings, some or all of which are then reloaned to the individual utilities. The most recent financing Orders for SIGECO and Indiana Gas were received on March 4, 2015. On June 15, 2016 an Order for long-term financing authority of $70 million of long-term debt and $75 million of equity financing was received from the PUCO for VEDO. Orders for SIGECO and Indiana Gas expire in December 2016 and the Order for VEDO expires in June 2017.

Consolidated Short-Term Borrowing Arrangements

At June 30, 2016, the Company has $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $311 million was available for the Utility Group operations and approximately $244 million was available for the wholly owned Nonutility Group and corporate operations. Both Vectren Capital’s and Utility Holdings’ short-term credit facilities are available through October 31, 2019. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions.

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

| (In millions) | Utility Group Borrowings 2016 | Utility Group Borrowings 2015 | Nonutility Group Borrowings 2016 | Nonutility Group Borrowings 2015 |
|---|---|---|---|---|
| As of June 30 | | | | |
| Balance Outstanding | $38.9 | $27.3 | $6.3 | $69.1 |
| Weighted Average Interest Rate | 0.71% | 0.36% | 1.59% | 1.28% |
| Six Months Ended June 30 Average | | | | |
| Balance Outstanding | $5.1 | $36.2 | $0.5 | $13.7 |
| Weighted Average Interest Rate | 0.60% | 0.39% | 1.60% | 1.30% |
| Maximum Month End Balance Outstanding | $38.9 | $121.5 | $6.3 | $69.1 |

| (In millions) | Utility Group Borrowings 2016 | Utility Group Borrowings 2015 | Nonutility Group Borrowings 2016 | Nonutility Group Borrowings 2015 |
|---|---|---|---|---|
| Quarterly Average - June 30 | | | | |
| Balance Outstanding | $7.2 | $3.5 | $1.0 | $27.2 |
| Weighted Average Interest Rate | 0.62% | 0.35% | 1.60% | 1.30% |
| Maximum Month End Balance Outstanding | $38.9 | $27.3 | $6.3 | $69.1 |

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan, stock option plan and other employee benefit plan requirements. New issuances added additional liquidity of $3.0 million for both the six months ended June 30, 2016 and 2015 periods and may be pushed down to the utilities.

California Department of Insurance

The California Department of Insurance issued a press release in January 2016 calling for all insurance companies doing business in California to disclose annually carbon-based investments and to voluntarily divest of their investments in thermal coal. The position on voluntarily divestiture taken by the California Insurance Commissioner, as defined, applies to electric utilities that derive more than 50 percent of their energy from thermal coal plants. The Company has a significant portion of its outstanding long term debt held by various insurance companies and placed through the private debt markets. The Company continues to monitor development in this area but anticipates no immediate impact.

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for property placed in service in 2015 - 2017; 40% in 2018; and 30% in 2019. Including the impact of alternative minimum tax credits that will be utilized in future periods, the extension of 50% bonus depreciation is expected to result in an approximate $35 million positive impact to cash flows for the 2016 tax year.

Potential Uses of Liquidity

Pension Funding Obligations

In 2016, the Company has contributed $15 million to its qualified pension plans. The Company does not anticipate making further contributions in 2016.

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at June 30, 2016, there are 42 open surety bonds supporting future performance.  The average face amount of these obligations is $9.6 million, and the largest obligation has a face amount of $51.0 million. The maximum exposure from these obligations is limited to the level of uncompleted work and further limited by bonds issued to ESG by various subcontractors. At June 30, 2016, approximately 45 percent of work was yet to be completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Based on a history of meeting performance obligations and installed products operating effectively, no liability or cost has been recognized for the periods presented. Since inception, ESG has paid a de minimis amount on performance obligations.

Corporate Guarantees
The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries. These guarantees do not represent incremental consolidated obligations; but rather, represent guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At June 30, 2016, parent level guarantees support a maximum of $250 million of ESG's performance contracting commitments, warranty obligations, project guarantees, and energy savings guarantees.

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

In addition, the Company has other guarantees outstanding, including letters of credit, supporting other consolidated subsidiary operations.

While there can be no assurance that the Company guarantee provisions will not be called upon, historically no such provisions have been called upon, and further, the Company believes that the likelihood of a material amount being triggered under any of these provisions is remote.

Planned Capital Expenditures & Investments
Utility capital expenditures are estimated at approximately $290 million for the remainder of 2016. Nonutility capital expenditures are estimated at approximately $40 million for the remainder of 2016.

Contractual Obligations
The Company's contractual obligations primarily consist of debt issued by SIGECO, Indiana Gas, Utility Holdings, and Vectren Capital; certain plant and nonutility plant purchase commitments, and other long-term liabilities. For the six months ended June 30, 2016, there were no significant changes to the Company's contractual obligations from those identified in the Company's Annual Report on Form 10-K for the year ended December 31, 2015, other than those which occur in the normal and ordinary course of business and those mentioned below.

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

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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 $293.3 million and $266.6 million for the six months ended June 30, 2016 and 2015, respectively. The increase in cash flow from operations in 2016 compared to 2015 is driven primarily by certain weather related working capital changes and timing of tax payments due to the passage of bonus depreciation. Weather related impacts include the fluctuation in the recoverable/refundable natural gas and fuel cost. Increases in accounts receivable in 2015 were driven by increased operating revenues at Infrastructure Services. Additionally, a significant decrease in prepaid taxes in 2015 was due to a federal refund received in 2015 related to the timing of the extension of bonus depreciation late in 2014.

Financing Cash Flow
Net cash flow required for financing activities was $105.6 million during the six months ended June 30, 2016 compared to requirements of $124.8 million in 2015. The decrease in cash flow required for financing activities was primarily related to an increase in cash required for payment of long term debt offset by net changes in short term borrowings. Financing activity also reflects the payment of dividends in both periods presented.

Investing Cash Flow
Cash flow required for investing activities was $246.5 million and $216.9 million during the six months ended June 30, 2016 and 2015, respectively. The primary use of cash in both periods reflects expenditures for utility capital expenditures.

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 legislation, litigation and government regulation, such as changes in or additions to tax laws or rates, pipeline safety regulation and environmental laws, including laws governing air emissions, including carbon, waste water discharges and the handling and disposal of coal combustion residuals that could impact the continued operation, and/or cost recovery of our generation plants and related assets. These compliance costs could substantially change the nature of the Company's generation fleet.

- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, physical attacks, cyber attacks, or other similar occurrences could adversely affect the Company's facilities, operations, financial condition, results of operations, and reputation.
- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as uncertainty surrounding the composition of state regulatory commissions, adverse regulatory changes, unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with interest rates, counter-party credit, and commodity prices. 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 use of derivatives. The Company executes derivative contracts in the normal course of operations while buying and selling commodities and occasionally when managing interest rate risk.

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

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Vectren 2015 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended June 30, 2016, 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 June 30, 2016, 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 June 30, 2016, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:
1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II

ITEM 1. LEGAL PROCEEDINGS

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

During the third quarter of 2014, the Company was notified of claims by a group of current and former SIGECO employees ("claimants") who participated in the Pension Plan for Salaried Employees of SIGECO ("SIGECO Salaried Plan"). That plan was merged into the Vectren Corporation Combined Non-Bargaining Retirement Plan ("Vectren Combined Plan") effective July 1, 2000. The claims relate to the claimants' election for benefits to be calculated under the Vectren Combined Plan's cash-balance formula rather than the SIGECO Salaried Plan formula. On March 12, 2015, certain claimants filed a Class Action Complaint against the Vectren Combined Plan and the Company in federal district court requesting that a class be certified and for various relief including that the Combined Plan be reformed and benefits thereunder be recalculated. The Company denied the allegations set forth in the Complaint and moved to dismiss the case. In April 2016, the court dismissed part of the compliant but allowed the remaining claims to proceed. The court will not consider the class certification issue until after the summary judgment stage of the case.

The Company is unable to quantify any potential impact of the claims. The Company does not expect, however, the outcome would have a material adverse effect on the Company's liquidity, results of operations or financial condition.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company's operating results and financial condition, causing them to be materially adversely affected. The Company's risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2015 Form 10-K and are therefore not presented herein.

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

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company's share-based compensation plans; however, no such open market purchases were made during the quarter ended June 30, 2016.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

| | |
|---|---|
| 10.1 | Vectren Corporation At Risk Compensation Plan (as amended and restated May 24, 2016) |
| 31.1 | Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer |
| 31.2 | Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer |
| 32 | Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002 |
| 101 | Interactive Data File |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema |

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| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase |

SIGNATURES

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

| | |
|---|---|
| | VECTREN CORPORATION<br>Registrant |
| August 4, 2016 | /s/M. Susan Hardwick<br>M. Susan Hardwick<br>Executive Vice President and<br>Chief Financial Officer<br>(Signing on behalf of the<br>registrant and as Principal<br>Accounting & Financial Officer) |

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