VECTREN UTILITY HOLDINGS INC
Form 10-K
March 05, 2015

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014
OR

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

For the transition period from __________________ to ________________________

Commission file number: 1-16739

VECTREN UTILITY HOLDINGS, INC.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

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

Large accelerated filer ¨ Accelerated filer ¨

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2014, was zero. All shares outstanding of the Registrant’s common stock were held by Vectren Corporation.

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

Common Stock - Without Par Value	10	February 27, 2015
Class	Number of Shares	Date

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Omission of Information by Certain Wholly Owned Subsidiaries

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

Definitions

AFUDC: allowance for funds used during construction

ASC: Accounting Standards Codification

BTU / MMBTU: British thermal units / millions of BTU

DOT: Department of Transportation

EPA: Environmental Protection Agency

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

IDEM: Indiana Department of Environmental Management

IRC: Internal Revenue Code

IURC: Indiana Utility Regulatory Commission

Kv: Kilovolt

GAAP: Generally Accepted Accounting Principles

MCF / BCF: thousands / billions of cubic feet

MDth / MMDth: thousands / millions of dekatherms

MISO: Midcontinent Independent System Operator

MW: megawatts

MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)

NERC: North American Electric Reliability Corporation

OCC: Ohio Office of the Consumer Counselor

OUCC: Indiana Office of the Utility Consumer Counselor

PUCO: Public Utilities Commission of Ohio

Throughput: combined gas sales and gas transportation volumes

XBRL: eXtensible Business Reporting Language

Access to Information

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

Mailing Address:
One Vectren Square
Evansville, Indiana 47708

Phone Number:
(812) 491-4000

Investor Relations Contact:
Robert L. Goocher
Treasurer and Vice President, Investor Relations
vvcir@vectren.com

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

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PART I
ITEM 1. BUSINESS

Description of the Business

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), Southern Indiana Gas and Electric Company (SIGECO), 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. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 575,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 electric customers and over 110,000 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 313,000 natural gas customers located near Dayton in west central Ohio.

Narrative Description of the Business

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

At December 31, 2014, the Company had $4.4 billion in total assets, with approximately $2.6 billion (59 percent) attributed to Gas Utility Services, $1.7 billion (39 percent) attributed to Electric Utility Services, and $0.1 billion (2 percent) attributed to Other Operations. Net income for the year ended December 31, 2014, was $148.4 million, with $57.0 million attributed to Gas Utility Services, $79.7 million attributed to Electric Utility Services, and $11.7 million attributed to Other Operations. Net income for the year ended December 31, 2013, was $141.8 million. For further information regarding the activities and assets of operating segments, refer to Note 13 in the Company's Consolidated Financial Statements included in Item 8.

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

Gas Utility Services

At December 31, 2014, the Company supplied natural gas service to approximately 1,011,100 Indiana and Ohio customers, including 924,000 residential, 85,400 commercial, and 1,700 industrial and other contract customers. Average gas utility customers served were approximately 998,200 in 2014, 992,100 in 2013, and 986,100 in 2012.

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

Revenues

The Company receives gas revenues by selling gas directly to customers at approved rates or by transporting gas through its pipelines at approved rates to customers that have purchased gas directly from other producers, brokers, or marketers. Total throughput was 239.2 MMDth for the year ended December 31, 2014. Gas sold and transported to residential and commercial customers was 122.6 MMDth representing 51 percent of throughput. Gas transported or sold to industrial and other contract customers was 116.6 MMDth representing 49 percent of throughput. Rates for transporting gas generally provide for the same margins earned by selling gas under applicable sales tariffs.

For the year ended December 31, 2014, gas utility revenues were approximately $944.6 million, of which residential customers accounted for 68 percent and commercial accounted for 24 percent. Industrial and other contract customers accounted for 8 percent of revenues.

Availability of Natural Gas

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

Natural Gas Purchasing Activity in Indiana

The Indiana utilities also enter into short term and long term contracts with third party suppliers to ensure availability of gas. Prior to June 18, 2013, the Company contracted with a wholly-owned subsidiary of ProLiance Holdings, LLC (ProLiance). ProLiance is an unconsolidated, nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy) (See the discussion in Note 5 in the Company’s Consolidated Financial Statements included in Item 8 regarding transactions with ProLiance). During 2014, the Company, through its utility subsidiaries, purchased all of its gas supply from third parties and 84 percent was from a single third party.

Natural Gas Purchasing Activity in Ohio

On April 30, 2008, the PUCO issued an order which approved the first two phases of a three phase plan to exit the merchant function in the Company's Ohio service territory. As a result, substantially all of the Company's Ohio customers now purchase natural gas directly from retail gas marketers rather than from the Company.

The PUCO provided for an Exit Transition Cost rider, which allows the Company to recover costs associated with the first two phases of the transition process. Exiting the merchant function has not had a material impact on earnings or financial condition. It, however, has and will continue to reduce Gas utility revenues and have an equal and offsetting impact to Cost of gas sold as VEDO, for the most part, no longer purchases gas for resale.

Total Natural Gas Purchased Volumes

In 2014, Utility Holdings purchased 87.9 MMDth volumes of gas at an average cost of $5.42 per Dth inclusive of demand charges. The average cost of gas per Dth purchased for the previous four years was $4.60 in 2013, $4.47 in 2012, $5.30 in 2011 and $5.99 in 2010.

Electric Utility Services

At December 31, 2014, the Company supplied electric service to approximately 143,300 Indiana customers, including approximately 124,600 residential, 18,500 commercial, and 200 industrial and other customers. Average electric utility customers served were approximately 142,900 in 2014, 142,300 in 2013 and 141,700 in 2012.

The principal industries served include polycarbonate resin (Lexan®) and plastic products; aluminum smelting and recycling; aluminum sheet products, automotive assembly, steel finishing, pharmaceutical and nutritional products; automotive glass; gasoline and oil products; ethanol; and coal mining.

Revenues

For the year ended December 31, 2014, retail electricity sales totaled 5,589.5 GWh, resulting in revenues of approximately $571.9 million. Residential customers accounted for 37 percent of 2014 revenues; commercial 27 percent; industrial 35 percent; and other 1 percent. In addition, in 2014 the Company sold 651.1 GWh through wholesale activities principally to the MISO. Wholesale revenues, including transmission-related revenue, totaled $52.9 million in 2014.

System Load

Total load for each of the years 2010 through 2014 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	8/27/2014	8/30/2013	7/24/2012	7/21/2011	8/4/2010
Total load at peak	1,095	1,102	1,259	1,220	1,275
Generating capability	1,298	1,298	1,298	1,298	1,298
Firm purchase supply	38	38	136	136	136
Interruptible contracts & direct load control	71	48	60	60	62
Total power supply capacity	1,407	1,384	1,494	1,494	1,496
Reserve margin at peak	22 %	25 %	19 %	22 %	17 %

The winter peak load for the 2013-2014 season of approximately 953 MW occurred on January 6, 2014. The prior year winter peak load for the 2012-2013 season was approximately 832 MW, occurring on February 1, 2013.

Generating Capability

Installed generating capacity as of December 31, 2014, was rated at 1,298 MW. Coal-fired generating units provide 1,000 MW of capacity, natural gas or oil-fired turbines used for peaking or emergency conditions provide 295 MW, and a landfill gas electric generation project provides 3 MW. Electric generation for 2014 was fueled by coal (98 percent), natural gas (2 percent), and landfill gas (less than 1 percent). Oil was used only for testing of gas/oil-fired peaking units. The Company generated approximately 5,546 GWh in 2014. Further information about the Company's owned generation is included in "Item 2 Properties."

Coal for coal-fired generating stations has been supplied from operators of nearby coal mines as there are substantial coal reserves in the southern Indiana area. Approximately 2.9 million tons were purchased for generating electricity during 2014, of which approximately 64 percent was supplied by Vectren Fuels, Inc (Vectren Fuels), previously Vectren's wholly owned subsidiary that was sold on August 29, 2014. This compares to 1.9 million tons and 2.1 million tons purchased in 2013 and 2012, respectively. The utility's coal inventory was approximately 600 thousand tons and 300 thousand tons at December 31, 2014 and 2013, respectively.

Coal Purchases

The average cost of coal per ton purchased and delivered for the last five years was $55.18 in 2014, $58.38 in 2013, $68.65 in 2012, $75.04 in 2011 and $70.47 in 2010. Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the Commission determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six-year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. See "Electric Rate and Regulatory Matters" in Item 8 regarding coal procurement procedures and electric fuel cost reductions.

Firm Purchase Supply

The Company, through SIGECO, has a 1.5 percent interest in the Ohio Valley Electric Corporation (OVEC). OVEC is owned by several electric utility companies, including SIGECO, and supplies power requirements to the United States Department of Energy's (DOE) uranium enrichment plant near Portsmouth, Ohio. The participating companies can receive from OVEC, and are obligated to pay for, any available power in excess of the DOE contract demand. At the present time, the DOE contract demand is essentially zero. The Company's 1.5 percent interest in OVEC makes available approximately 30 MW of capacity. The Company purchased approximately 167 GWh from OVEC in 2014.

In April 2008, the Company executed a capacity contract with Benton County Wind Farm, LLC to purchase as much as 30 MW from a wind farm located in Benton County, Indiana, with the approval of the IURC. The contract expires in 2029. In 2014, the Company purchased approximately 58 GWh under this contract.

In December 2009, the Company executed a 20 year power purchase agreement with Fowler Ridge II Wind Farm, LLC to purchase as much as 50 MW of energy from a wind farm located in Benton and Tippecanoe Counties in Indiana, with the approval of the IURC. In 2014, the Company purchased 147 GWh under this contract.

MISO Related Activity

The Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electric transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities as well as that of other utilities in the region. The Company is an active participant in the MISO energy markets, where it bids its generation into the Day Ahead and Real Time markets and procures power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market. MISO-related purchase and sale transactions are recorded using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded as purchased power in Cost of fuel & purchased power and net sales in a single hour are recorded in Electric utility revenues. During 2014, in hours when purchases from the MISO were in excess of generation sold to the MISO, the net purchases were 490 GWh. During 2014, in hours when sales to the MISO were in excess of purchases from the MISO, the net sales were 651 GWh.

Capacity Purchase

In May 2008, the Company executed a MISO capacity purchase from Sempra Energy Trading, LLC to purchase 100 MW of name plate capacity from its generating facility in Dearborn, Michigan. The term of the contract began January 1, 2010 and expired on December 31, 2012. The Company has not replaced this contract.

Interconnections

The Company has interconnections with Louisville Gas and Electric Company, Duke Energy Shared Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc. and Big Rivers Electric Corporation providing the ability to simultaneously interchange approximately 900 MW during peak load periods. The Company, as required as a member of the MISO, has turned over operational control of the interchange facilities and its own transmission assets to MISO. The Company in conjunction with the MISO must operate the bulk electric transmission system in accordance with NERC Reliability

Standards. As a result, interchange capability varies based on regional transmission system configuration, generation dispatch, seasonal facility ratings, and other factors.

Competition

The utility industry has undergone structural changes for several years, resulting in increasing competitive pressures faced by electric and gas utility companies. Currently, several states have passed legislation allowing electricity customers to choose their electricity supplier in a competitive electricity market and several other states have considered such legislation. At the present time, Indiana has not adopted such legislation. Ohio regulation allows gas customers to choose their commodity supplier. The Company implemented a choice program for its gas customers in Ohio in January 2003. Substantially all of VEDO's customers receive gas from third-party suppliers and at December 31, 2014, approximately 128,000 customers in Vectren’s Ohio service territory had selected their supplier. In addition, VEDO’s service territory continues to transition toward exiting the merchant function. Margin earned for transporting natural gas to those customers, who have purchased natural gas from another supplier, is generally the same as that earned by selling gas under Ohio tariffs. Indiana has not adopted any regulation requiring gas choice; however, the Company operates under approved tariffs permitting certain industrial and commercial large volume customers to choose their commodity supplier.

Increased competition, including those from cogeneration, solar, and other renewables opportunities for customers, create competitive pressures. In this regard, the deployment and commercialization of disruptive technologies, such as renewable energy sources and cogeneration facilities, have the potential to change the nature of the utility industry and reduce demand for the Company's electric and gas products and services. If the Company is not able to appropriately adapt to structural changes in the utility industry as a result of the development of disruptive technologies, this may have an adverse effect on the Company's financial condition and results of operations.

Regulatory and Environmental Matters

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

Personnel

As of December 31, 2014, the Company and its consolidated subsidiaries had approximately 1,500 employees, of which 700 are subject to collective bargaining arrangements.

In July 2014, the Company reached a three-year labor agreement with Local 1393 of the International Brotherhood of Electrical Workers and United Steelworkers of America Locals 12213 and 7441, ending December 1, 2017. This labor agreement relates to employees of Indiana Gas.

In June 2013, the Company reached a three year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 30, 2016. This labor agreement relates to employees of SIGECO.

In December 2012, the Company reached a three year agreement with Local 175 of the Utility Workers Union of America. The labor agreement was retroactively effective to November 1, 2012 and ends October 31, 2015. This labor agreement relates to employees of VEDO.

In September 2012, the Company reached a three year agreement with Local 135 of the Teamsters, Chauffeurs, Warehousemen, and Helpers Union, ending September 23, 2015. This labor agreement relates to employees of SIGECO.

ITEM 1A. RISK FACTORS

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

Utility Holdings is a holding company and its assets consist primarily of investments in its subsidiaries.

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

Deterioration in general economic conditions may have adverse impacts.

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

Financial market volatility could have adverse impacts.

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

Utility Holdings has long-term and short-term debt guaranteed by its subsidiaries.

Utility Holdings currently has outstanding long-term and short-term debt that is jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. These guarantees do not represent incremental consolidated obligations; rather, they represent guarantees of Utility Holdings' obligations.

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

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

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

SIGECO’s senior secured debt	Aa3	A

The current outlook for both Moody's and Standard & Poor’s is stable. Both rating agencies categorize the ratings of the above securities as investment grade. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to

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revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard & Poor’s and Moody’s lowest level investment grade rating is BBB- and Baa3, respectively.

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

Utility Holdings’ gas and electric utility sales are concentrated in the Midwest.

The operations of the Company’s regulated utilities are concentrated in central and southern Indiana and west central Ohio and are therefore impacted by changes in the Midwest economy in general and changes in particular industries concentrated in the Midwest. These industries include automotive assembly, parts and accessories; feed, flour and grain processing; metal castings, aluminum products, polycarbonate resin (Lexan®) and plastic products; gypsum products; electrical equipment, metal specialties, glass and steel finishing; aluminum smelting and recycling; pharmaceutical and nutritional products; gasoline and oil products; ethanol; and coal mining.

Utility Holdings operates in an increasingly competitive industry, which may affect its future earnings.

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

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

Utility Holdings’ electric utility sales are sensitive to variations in weather conditions. The Company forecasts utility sales on the basis of normal weather. Since the Company does not have a weather-normalization mechanism for its electric operations, significant variations from normal weather could have a material impact on its earnings. However, the impact of weather on the gas operations in the Company’s Indiana territories has been significantly mitigated through the implementation of a normal temperature adjustment mechanism. Additionally, the implementation of a straight fixed variable rate design mitigates most weather variations related to Ohio residential gas sales.

Utility Holdings' businesses are exposed to increasing regulation, including pipeline safety, environmental, and cybersecurity regulation.

The Company's utilities are subject to regulation by federal, state, and local regulatory authorities and are exposed to public policy decisions that may negatively impact the Company's earnings. In particular, the Company is subject to regulation by the

FERC, the NERC, the EPA, the IURC, the PUCO, the DOT, Department of Energy (DOE), Occupational Safety and Health Administration (OSHA), and Department of Homeland Security (DHS). These authorities regulate many aspects of its generation, transmission and distribution operations, including construction and maintenance of facilities, operations, and safety. In addition, the IURC, PUCO, and FERC approve its utility-related debt and equity issuances, regulate the rates that the Company's utilities can charge customers, the rate of return that the Company's utilities are authorized to earn, and their ability to timely recover gas and fuel costs and investments in infrastructure. Further, there are consumer advocates and other parties that may intervene in regulatory proceedings and affect regulatory outcomes.

Trends Toward Stricter Standards

With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated that are subject to regulation, the Company's investment in infrastructure, and the associated operating costs have increased and are expected to increase in the future. As examples of the trend toward stricter regulation, the EPA is currently considering revisions to regulations involving fly ash disposal, cooling tower intake facilities, wastewater discharges, and greenhouse gases and continues to implement increasingly more stringent air quality standards.

Pipeline Safety Considerations

The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe, efficient, and reliable manner. The Company's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continuous renewal and improvement. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law on January 3, 2012. While certain of the compliance costs remain uncertain, the Pipeline Safety Law resulted in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses as evidenced by recent regulatory filings and resulting Commission Orders in Indiana and Ohio by SIGECO, Indiana Gas, and VEDO.

Environmental Considerations

The Company's utility operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and 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), mercury, and non-hazardous substances such as coal combustion residuals, among others. Environmental legislation/regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition.

Climate Change and Renewable Energy Considerations

On June 2, 2014, the EPA proposed its rule for states to regulate carbon dioxide (CO2) emissions from existing electric generating units. The rule, when final will require states to adopt plans that reduce CO2 emissions by 30 percent from 2005 levels by 2030. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA’s proposal have begun. Similarly, in the President's Climate Action Plan on methane emissions released in March of 2014, new actions were outlined to require 40 to 45 percent reduction in methane emissions from upstream sources, specifically targeting new and modified oil and natural gas production wells. Downstream sources, such as local distribution companies, will be encouraged to participate in a new voluntary methane emissions monitoring and reduction program. If these regulations are finalized by the EPA, or if legislation requiring reductions in CO2 and other GHGs or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. 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 greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. At this time and in the absence of final legislation or regulatory mandates, compliance costs and other effects associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain.

Evolving Physical Security and Cybersecurity Standards and Considerations
The frequency, size and variety of physical security and cybersecurity threats against critical infrastructure companies continues to grow, as do the evolving frameworks, standards and regulations intended to keep pace with and address these threats. In 2013 and 2014, there was a marked increase in interest from both federal and state regulatory agencies related to physical security and cybersecurity in general, and specifically in critical infrastructure sectors, including the electric and natural gas sectors. The Company has dedicated internal and third party physical security and cybersecurity teams and maintains vigilance with regard to the communication and assessment of physical security and cybersecurity risks and the measures employed to protect information technology assets, critical infrastructure, the Company and its customers from these threats. Physical security and cybersecurity threats, however, constantly evolve in attempts to identify and capitalize on any weakness or unprotected areas. If these measures were to fail or if a breach were to occur, it could result in impairment or loss of critical functions, operating reliability, customer or other confidential information. The ultimate effects which are difficult to quantify with any certainty are partially limited through insurance.

Increasing regulation and infrastructure replacement programs could affect Utility Holdings' utility rates charged to customers, its costs, and its profitability.

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

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

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

Utility Holdings’ energy delivery operations are subject to various risks.

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

Utility Holdings’ power supply operations are subject to various risks.

The Company’s electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased purchase power costs. Such operational risks can arise from circumstances such as facility shutdowns due to equipment failure or operator error; interruption of fuel supply or increased prices of fuel as contracts expire; disruptions in the delivery of electricity; inability to comply with regulatory or permit requirements; labor disputes; and natural disasters.

The Company participates in the MISO.

The Company is a member of the MISO, which serves the electric transmission needs of much of the Midcontinent region and maintains operational control over the Company's electric transmission facilities, as well as that of other utilities in the region. As a result of such control, the Company's continued ability to import power, when necessary, and export power to the wholesale market has been, and may continue to be, impacted.

The need to expend capital for improvements to the regional electric transmission system, both to the Company's facilities as well as to those facilities of adjacent utilities, over the next several years is expected to be significant. The Company timely recovers its investment in certain new electric transmission projects that benefit the MISO infrastructure at a FERC approved rate of return, which is currently under review based on a joint complaint filed against MISO and various MISO transmission owners, including the Company. The FERC has yet to rule on the case and the Company is currently unable to predict the outcome of the proceeding.

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

Wholesale power marketing activities may add volatility to earnings.

Utility Holdings' regulated electric utility engages in wholesale power marketing activities that primarily involve the offering of utility-owned or contracted generation into the MISO hourly and real time markets. As part of these strategies, the Company may also execute energy contracts that are integrated with portfolio requirements around power supply and delivery. Presently, margin earned from these activities above or below $7.5 million per year is shared evenly with customers. These earnings from wholesale marketing activities may vary based on fluctuating prices for electricity and the amount of electric generating capacity or purchased power available beyond that needed to meet firm service requirements. In addition, this earnings sharing approach may be modified in future regulatory proceedings.

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

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

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

The trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and air conditioners and other heating and cooling devices as well as lighting, may reduce the demand for energy products. Prices for natural gas are subject to volatile fluctuations in response to changes in supply and other market conditions. During periods of high energy commodity costs, the Company's prices generally increase, which may lead to customer conservation. State and/or federal regulation may require mandatory conservation measures, which would reduce the demand for energy products. In addition, the Company's customers, especially large commercial and industrial customers, may choose to employ various technological advances to develop alternative energy sources, such as the construction and development of wind power, solar technology, or electric cogeneration facilities. Increased conservation efforts and the utilization of technological advances to increase energy efficiency or to develop alternate energy sources could lead to a reduction in demand for the Company’s energy products and services, which could have an adverse effect on its revenues and overall results of operations.

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

A changing climate creates uncertainty and could result in broad changes to the Company’s service territories. These impacts could include, but are not limited to, population shifts; changes in the level of annual rainfall; changes in the weather; and changes to the frequency and severity of weather events such as thunderstorms, wind, tornadoes, and ice storms that can damage infrastructure. Such changes could impact the Company in a number of ways including the number and/or type of customers in the Company’s service territories; the demand for energy resulting in the need for additional investment in generation assets or the need to retire current infrastructure that is no longer required; an increase to the cost of providing service; and an increase in the likelihood of capital expenditures to replace damaged infrastructure.

To the extent climate change impacts a region’s economic health, it may also impact the Company’s revenues, costs, and capital structure and thus the need for changes to rates charged to regulated customers. Rate changes themselves can impact the economic health of the communities served and may in turn adversely affect the Company’s operating results.

Increased derivative regulation could impact results.

The Company uses commodity derivative instruments in conjunction with procurement activities. The Company may also periodically use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances.

Regulations related to the use of derivatives that became law in 2010 under the Dodd-Frank Wall Street Reform and Consumer Protection Act continue to evolve and their ultimate application remains uncertain. Depending on the continued evolution of the regulations adopted by the Commodity Futures Trading Commission (CFTC) and other agencies, the Company may be required to post additional collateral with dealer counterparties for commitments and interest rates, physical or financial commodity derivative transactions and report or otherwise disclose such activity to dealer counterparties or other agencies. The law provides for an exception from these clearing and cash collateral requirements for commercial end-users. Requirements to post collateral could limit cash for investment and for other corporate purposes or could increase debt levels and resulting interest expense. In addition, a requirement for counterparties to post collateral could result in additional costs associated with executing transactions, thereby decreasing profitability. An increased collateral requirement could also reduce the Company’s ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. The regulations may also limit the pool of potential counterparties and/or the liquidity in the respective markets for such transactions.

Significant rule-making by numerous governmental agencies, particularly the CFTC, continues to evolve and has been subject to a number of extensions and delays. The Company continues to evaluate the impacts of these rulemakings and interpretations as they become available.

From time to time, Utility Holdings is subject to material litigation and regulatory proceedings.

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

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

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

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

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

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

The Company relies on information technology networks and systems to operate its generating facilities, engage in asset management activities, and process, transmit and store electronic information including customer and employee information. Security breaches of this information technology infrastructure could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information. In particular, any data loss or information security lapses resulting in the compromise of personal information or the improper use or disclosure of sensitive or classified information could result in claims, remediation costs, regulatory sanctions against the Company, loss of current and future contracts, and serious harm to the Company's reputation. While the Company has implemented policies, procedures, and controls to prevent and detect these activities, not all misconduct may be prevented. In the event of a severe infrastructure system disruption or generating facility shutdown resulting from such events, the Company has contingency plans and employs crisis management to respond and recover operations. Despite these measures, if such an attack or security breach were to occur, results of operations and financial condition could be materially adversely affected. The ultimate effects, which are difficult to quantify with any certainty, are partially limited through insurance.

Workforce risks could affect Utility Holdings' financial results.

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

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

The Company relies on third party contractors and other agents and business partners to perform some of the services provided to its customers, as well as to handle physical security and cybersecurity functions. Any misconduct by these third parties, or the Company’s inability to properly manage them, could adversely impact the provision of services to customers and the quality of services provided. Misconduct could include fraud or other improper activities, such as falsifying records and violations of laws. Other examples could include the failure to comply with the Company’s policies and procedures or with government

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procurement regulations, regulations regarding the use and safeguarding of classified or other protected information, legislation regarding the pricing of labor and other costs in government contracts, laws and regulations relating to environmental, health or safety matters, bribery of foreign government officials, import-export control, lobbying or similar activities, and any other applicable laws or regulations. Any data loss or information security lapses resulting in the compromise of personal information or the improper use or disclosure of sensitive or classified information could result in claims, remediation costs, regulatory sanctions against the Company, loss of current and future contracts, and serious harm to its reputation. Although the Company has implemented policies, procedures, and controls to prevent and detect these activities, these precautions may not prevent all misconduct, and as a result, the Company could face unknown risks or losses. The Company's failure to comply with applicable laws or regulations or misconduct by any of its contractors, agents, or business partners could damage its reputation and subject it to fines and penalties, restitution or other damages and loss of current and future customer contracts any of which would adversely affect the business and future results.

The performance of Vectren’s nonutility businesses may impact Utility Holdings.

Execution of Vectren’s nonutility business strategies and the success of efforts to invest in and develop new opportunities in the nonutility business area are subject to a number of risks.

Related to Vectren's nonutility infrastructure services activities, Vectren Infrastructure Services Corporation (VISCO), is wholly owned by Vectren and provides underground pipeline construction and repair services for customers including Utility Holdings. Risks specific to VISCO's strategies include, but are not limited to, success in bidding contracts; variations in the volume of contract work; unanticipated cost increases in completion of the contracted work; increases to funding requirements associated with multiemployer pension plans; the ability to attract and retain qualified employees; cancellation of projects by customers and/or reductions in the scope of the projects; ability to obtain materials and equipment required to perform services from suppliers and manufacturers.

Related to Vectren's nonutility energy services activities, Vectren Energy Services Corporation (VESCO), is wholly owned by Vectren and provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Risks specific to VESCO's strategies include, but are not limited to, success in bidding contracts; changes in legislation and regulations impacting the industries in which the customers served by Energy Services operate; failure to properly estimate the cost to construct projects; the inability to attract and retain qualified employees; risks associated with projects owned or operated; cancellation of projects by customers and/or reductions in the scope of the projects; credit worthiness of customers; and changing market conditions.

In addition, there are other risks impacting Vectren’s nonutility operations including the effects of weather; failure of installed performance contracting products to operate as planned; failure to develop or obtain gas storage field; potential legislation that may limit CO2 and other greenhouse gas emissions; creditworthiness of customers and joint venture partners; changes in federal, state or local legal requirements, such as changes in tax laws or rates; and changing market conditions.

Vectren’s nonutility infrastructure services business supports Utility Holdings’ utilities pursuant to infrastructure service contracts. In most instances, Vectren’s ability to maintain these service contracts depends upon regulatory discretion and negotiation with interveners, and there can be no assurance that it will be able to obtain future service contracts, or that existing arrangements will not be revisited.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Gas Utility Services

Indiana Gas owns and operates four active gas storage fields located in Indiana covering 58,100 acres of land with an estimated ready delivery from storage capability of 5.6 BCF of gas with maximum peak day delivery capabilities of 145,500 MCF per day. Indiana Gas also owns and operates three propane plants located in Indiana with the ability to store 1.5 million gallons of propane and manufacture for delivery 33,000 MCF of manufactured gas per day. In addition to its company-owned storage and propane capabilities, Indiana Gas has contracted for 16.1 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 239,200 MMBTU per day. Indiana Gas’ gas delivery system includes 13,100 miles of distribution and transmission mains, all of which are in Indiana except for pipeline facilities extending from points in northern Kentucky to points in southern Indiana so that gas may be transported to Indiana and sold or transported by Indiana Gas to ultimate customers in Indiana.

SIGECO owns and operates three active underground gas storage fields located in Indiana covering 6,100 acres of land with an estimated ready delivery from storage capability of 5.3 BCF of gas with maximum peak day delivery capabilities of 88,000 MCF per day. In addition to its company-owned storage delivery capabilities, SIGECO has contracted for 0.4 BCF of interstate pipeline storage service with a maximum peak day delivery capability of 16,800 MMBTU per day. SIGECO's gas delivery system includes 3,200 miles of distribution and transmission mains, all of which are located in Indiana.

VEDO has contracted for 11.8 BCF of natural gas delivery service with a maximum peak day delivery capability of 246,100 MMBTU per day. While the Company still has title to this delivery capability, it has released it to those retail gas marketers now supplying VEDO’s customers with natural gas, and those suppliers are responsible for the demand charges. VEDO’s gas delivery system includes 5,500 miles of distribution and transmission mains, all of which are located in Ohio.

Electric Utility Services

SIGECO's installed generating capacity as of December 31, 2014, was rated at 1,298 MW. SIGECO's coal-fired generating facilities are the Brown Station with two units of 490 MW of combined capacity, located in Posey County approximately eight miles east of Mt. Vernon, Indiana; the Cully Station with two units of 360 MW of combined capacity; and Warrick Unit 4 with 150 MW of capacity. Both the Culley and Warrick stations are located in Warrick County near Yankeetown, Indiana. SIGECO's gas-fired turbine peaking units are: two 80 MW gas turbines (Brown Unit 3 and Brown Unit 4) located at the Brown Station; two Broadway Avenue Gas Turbines located in Evansville, Indiana with a combined capacity of 115 MW (Broadway Avenue Unit 1, 50 MW and Broadway Avenue Unit 2, 65 MW); and two Northeast Gas Turbines located northeast of Evansville in Vanderburgh County, Indiana with a combined capacity of 20 MW. The Brown Unit 3 and Broadway Avenue Unit 2 turbines are also equipped to burn oil. Total capacity of SIGECO's six gas turbines is 295 MW, and they are generally used only for reserve, peaking, or emergency purposes due to the higher per unit cost of generation. SIGECO also has a landfill gas electric generation project in Pike County, Indiana with a total generation capability of 3 MW.

SIGECO's transmission system consists of 1,027 circuit miles of 345Kv, 138Kv and 69Kv lines. The transmission system also includes 37 substations with an installed capacity of 4,722 megavolt amperes (Mva). The electric distribution system includes 4,560 circuit miles of lower voltage overhead lines and 402 trench miles of conduit containing 2,325 circuit miles of underground distribution cable. The distribution system also includes 95 distribution substations with an installed capacity of 2,995 Mva and 52,267 distribution transformers with an installed capacity of 2,330 Mva.

SIGECO owns utility property outside of Indiana approximating 24 miles of 138Kv and 345Kv electric transmission lines, which are included in the 1,027 circuit miles discussed above. These assets are located in Kentucky and interconnect with Louisville Gas and Electric Company's transmission system at Cloverport, Kentucky and with Big Rivers Electric Cooperative at Sebree, Kentucky.

Property Serving as Collateral

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

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company 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 consolidated financial statements are included in "Item 8 Financial Statements and Supplementary Data."

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 in effect prior to the formation of Vectren.

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 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Common Stock Market Price

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

Dividends Paid to Parent

In the first quarter of 2015, Utility Holdings paid a $27.6 million dividend to its parent company.

During 2014, Utility Holdings paid dividends of $27.1 million to its parent company in each quarter.

During 2013, Utility Holdings paid dividends of $26.3 million to its parent company in each quarter.

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

ITEM 6. SELECTED FINANCIAL DATA

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

	Year Ended December 31,				
(In millions)	2014	2013	2012	2011	2010
Operating Data:					
Operating revenues	$1,569.7	$1,429.6	$1,333.6	$1,457.0	$1,563.7
Operating income	281.4	281.6	286.8	281.8	277.0
Net income	148.4	141.8	138.0	122.9	123.9
Balance Sheet Data:					
Total assets	$4,428.1	$4,140.8	$4,046.8	$3,974.5	$3,924.5
Long-term debt - net of current maturities & debt subject to tender	1,162.3	1,257.1	1,103.4	1,208.2	1,024.8
Common shareholder's equity	1,478.5	1,432.8	1,390.0	1,346.6	1,315.4

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

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

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

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

Executive Summary of Consolidated Results of Operations

During 2014, Utility Holdings earned $148.4 million, compared to $141.8 million in 2013 and $138.0 million in 2012. The
improved results in 2014 are primarily driven by increased gas and electric margins partially offset by higher operating expenses from increased performance-based compensation expense and gas system maintenance resulting from the harsh winter in the first half of the year.

Gas utility services

The gas utility segment earned $57.0 million during the year ended December 31, 2014, compared to earnings of $55.7 million in 2013 and $60.0 million in 2012. The increased results in 2014 were due to increased customer margin from returns on the Ohio infrastructure replacement programs and small customer growth. This increase in margin was partially offset by higher operating expenses from increased performance-based compensation expense and increased weather-related maintenance of the gas system during the first half of 2014. In 2013, as compared to 2012, increases in operating costs more than offset margin increases. The increased operating costs were primarily the result of the acceleration of maintenance projects that were completed in 2013 and increased depreciation expense.

Electric utility services

The electric operations earned $79.7 million during 2014, compared to earnings of $75.8 million in 2013 and $68.0 million in 2012. Improved 2014 results were due primarily to the impact of weather on retail electric margin, which management estimates the after tax impact to be approximately $1.1 million favorable compared to 2013 as well as an increase in lost revenue recovery related to electric conservation programs, which had an after tax favorable impact of $2.3 million. Results were also favorably impacted by increased deferral of interest on construction projects. These improved results were offset somewhat by higher operating costs, including higher performance-based compensation and the acceleration of power supply maintenance projects completed in the current year.

Other utility operations

In 2014, earnings from other utility operations were $11.7 million, compared to $10.3 million in 2013 and $10.0 million in 2012. A lower income tax rate in 2014, primarily driven by the revaluation of Utility Holdings' deferred income taxes related to Vectren's sale of Vectren Fuels and the rate reduction from a change in the Indiana tax legislation passed in 2014, resulted in higher earnings in 2014.

The Regulatory Environment

Gas and electric operations, with regard to retail rates and charges, terms of service, accounting matters, financing, and certain other operational matters specific to its Indiana customers (the operations of SIGECO and Indiana Gas), are regulated by the IURC. The retail gas operations of VEDO are subject to regulation by the PUCO.

In the Company's two Indiana natural gas service territories, normal temperature adjustment (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to residential and commercial customers due to weather and changing consumption patterns. Similar usage risks in Ohio are diminished by a straight fixed variable rate design for the Company's residential customers. In addition to these mechanisms, the commissions have authorized specific bare steel and cast iron replacement programs in all natural gas service territories, and an expanded gas infrastructure replacement program in Indiana, which allow for recovery of these investments outside of a base rate case proceeding. Further, rates charged to natural gas customers in Indiana contain a gas cost adjustment (GCA) clause and electric rates contain a fuel adjustment clause (FAC). Both of these cost tracker mechanisms allow for the timely adjustment in charges to reflect changes in the cost of gas and cost for fuel. The Company utilizes similar mechanisms for other material operating costs, which allow for changes in revenue outside of a base rate case. The implementation of these various mechanisms has allowed the Company to avoid regulatory proceedings to increase base rates since 2011 for its electric business and 2009 for its gas business.

Rate Design Strategies
Sales of natural gas and electricity to residential and commercial customers are largely seasonal and are impacted by weather. Trends in the average consumption among natural gas residential and commercial customers have tended to decline as more efficient appliances and furnaces are installed and the Company's utilities have implemented conservation programs. In the Company's two Indiana natural gas service territories, normal temperature adjustment and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns. The Ohio natural gas service territory has a straight fixed variable rate design for its residential customers. This rate design, which was fully implemented in February 2010, mitigates approximately 90 percent of the Ohio service territory's weather risk and risk of decreasing consumption specific to its small customer classes.

In all natural gas service territories, the commissions have authorized bare steel and cast iron replacement programs. In Indiana, state laws were passed in 2012 and 2013 that expand the ability of utilities to recover, outside of a base rate proceeding, certain costs of federally mandated projects and other significant gas distribution and transmission infrastructure replacement investments. Legislation was passed in 2011 in Ohio that support the investment in other capital projects, allowing the utility to defer the impacts of these investments until its next base rate case. The Company has received approval to implement these mechanisms in both states.

SIGECO's electric service territory currently recovers certain transmission investments outside of base rates. The electric service territory has neither an NTA nor a decoupling mechanism; however, rate designs provide for a lost margin recovery mechanism that works in tandem with conservation initiatives.

Tracked Operating Expenses
Gas costs and fuel costs incurred to serve Indiana customers are two of the Company's most significant operating expenses. Rates charged to natural gas customers in Indiana contain a gas cost adjustment clause. The GCA clause allows the Company to timely charge for changes in the cost of purchased gas, inclusive of unaccounted for gas expense based on actual experience and subject to caps that are based on historical experience. Electric rates contain a fuel adjustment clause that allows for timely adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to an approved variable benchmark based on The New York Mercantile Exchange (NYMEX) natural gas prices, is also timely recovered through the FAC.
GCA and FAC procedures involve periodic filings and IURC hearings to establish price adjustments for a designated future period. The procedures also provide for inclusion in later periods of any variances between actual recoveries representing the estimated costs and actual costs incurred. Since April 2010, the Company has not been the supplier of natural gas in its Ohio territory.
The IURC has also applied the statute authorizing GCA and FAC procedures to reduce rates when necessary to limit net operating income to a level authorized in its last general rate order through the application of an earnings test. The

last time the Company was impacted by this earnings test was in the electric FAC in 2012.

In Indiana, gas pipeline integrity management operating costs, costs to fund energy efficiency programs, MISO costs, and the gas cost component of uncollectible accounts expense based on historical experience are recovered by mechanisms outside of typical base rate recovery. In addition, certain operating costs, including depreciation, associated with federally mandated

investments, gas distribution and transmission infrastructure replacement investments, and regional electric transmission assets not in base rates are also recovered by mechanisms outside of typical base rate recovery.
In Ohio, expenses such as uncollectible accounts expense, costs associated with exiting the merchant function, and costs associated with the infrastructure replacement program and other gas distribution capital expenditures are subject to recovery outside of base rates.
Revenues and margins in both states are also impacted by the collection of state mandated taxes, which primarily fluctuate with gas and fuel costs.

Base Rate Orders
Over the last eight years, regulatory orders establishing new base rates have been received by each utility. SIGECO's electric territory received an order in April 2011, with rates effective May 2011, and its gas territory received an order and implemented rates in August 2007. Indiana Gas received its most recent base rate order and implemented rates in February 2008, and VEDO received an order in January 2009, with implementation in February 2009. The orders authorize a return on equity ranging from 10.15 percent to 10.40 percent. The authorized returns reflect the impact of rate design strategies that have been authorized by these state commissions.

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

Operating Trends

Margin

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

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

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
Gas utility revenues	$944.6	$810.0	$738.1
Cost of gas sold	468.7	358.1	301.3
Total gas utility margin	$475.9	$451.9	$436.8
Margin attributed to:			
Residential & commercial customers	$347.4	$341.1	$333.9
Industrial customers	59.3	58.0	55.2
Other	11.1	9.7	9.5
Regulatory expense recovery mechanisms	58.1	43.1	38.2
Total gas utility margin	$475.9	$451.9	$436.8
Sold & transported volumes in MMDth attributed to:			

Residential & commercial customers	122.6	111.9	90.2
Industrial customers	116.6	111.7	105.8
Total sold & transported volumes	239.2	223.6	196.0

Gas Utility margins were $475.9 million for the year ended December 31, 2014, and compared to 2013, increased $24.0 million. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 110 percent of normal in Ohio and 107 percent of normal in Indiana during 2014, compared to 103 percent of normal in Ohio and 102 percent of normal in Indiana during 2013, had a slight favorable impact on small customer margin. However, colder weather did increase sold and transported volumes, which was the primary driver in the higher regulatory expense recovery margin and a corresponding increase in operating expenses. Regulatory expense recovery margin increased $15.0 million compared to 2013. Customer margin increased $3.8 million compared to 2013 from small customer growth and large customer usage. Additionally, margin was favorably impacted by $3.5 million from the return from infrastructure replacement programs, particularly in Ohio.

For the year ended December 31, 2013, Gas Utility margins increased $15.1 million compared to 2012. Customer margin increased approximately $8.7 million in 2013 from customer growth and returns generated on infrastructure replacement programs in Ohio. Heating degree days that were 103 percent of normal in Ohio and 102 percent of normal in Indiana during 2013, compared to 88 percent of normal in Ohio and 79 percent of normal in Indiana in 2012, had an approximate $0.8 million favorable impact on small customer margin. However, weather, which led to higher volumes, was the primary driver in the higher regulatory expense recovery margin, which increased $4.9 million compared to 2012.

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
Electric utility revenues	$624.8	$619.3	$594.9
Cost of fuel & purchased power	201.8	202.9	192.0
Total electric utility margin	$423.0	$416.4	$402.9
Margin attributed to:			
Residential & commercial customers	$260.8	$255.8	$255.8
Industrial customers	111.2	108.7	108.5
Other	5.5	4.8	1.6
Regulatory expense recovery mechanisms	11.6	10.5	4.9
Subtotal: Retail	389.1	379.8	370.8
Wholesale margin	33.9	36.6	32.1
Total electric utility margin	$423.0	$416.4	$402.9
Electric volumes sold in GWh attributed to:			
Residential & commercial customers	2,762.3	2,722.1	2,731.7
Industrial customers	2,804.6	2,735.2	2,710.5
Municipals & other	22.6	21.8	22.6
Total retail & firm wholesale volumes sold	5,589.5	5,479.1	5,464.8

Retail
Electric retail utility margins were $389.1 million for the year ended December 31, 2014 and, compared to 2013, increased by $9.3 million. As energy conservation initiatives continue, the Company's lost revenue recovery contributed increased margin of $3.9 million related to electric conservation programs compared to the prior year. Electric results, which are not protected by weather normalizing mechanisms, experienced a $1.8 million increase from weather in small customer margin as heating degree days were 107 percent of normal in 2014 compared to 102 percent of normal in 2013 and cooling degree days were 104 percent of normal in 2014 compared to 103 percent of normal in 2013. Results also reflect increased large customer usage, which had a favorable margin impact of $2.0 million. Margin from regulatory expense recovery mechanisms increased $1.1 million driven primarily by a

corresponding increase in operating expenses associated with MISO costs.

In 2013, Electric retail utility margins were $379.8 million for the year ended December 31, 2013 and, compared to 2012, increased by $9.0 million. Cooling degree days in 2013 were 103 percent of normal compared to 130 percent of normal in 2012, resulting in lower small customer margin of $1.2 million, largely offset by an increase in customers. Large customer margins for 2013 were relatively flat when compared to 2012. Other margin was higher in 2013 by $3.2 million, due in part to $2.6 million in refunds to customers during 2012 resulting from statutory net operating income limits. Margin from regulatory expense recovery mechanisms increased $5.6 million in 2013 compared to 2012, driven by a corresponding increase in operating expenses associated with the electric state-mandated conservation programs.

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:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Transmission system margin	$26.1	$29.4	$26.4
Off-system margin	7.8	7.2	5.7
Total wholesale margin	$33.9	$36.6	$32.1

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $26.1 million during 2014, compared to $29.4 million in 2013 and $26.4 million in 2012. Results in 2014 reflect lower returns on transmission investments due to a reserve recorded associated with a pending FERC ROE complaint. To date, the Company has invested $157.7 million in qualifying projects. The net plant balance for these projects totaled $143.6 million at December 31, 2014. 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. Operating expenses are also recovered. As mentioned above, the Company has established a reserve pending the outcome of this complaint. 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.

For the year ended December 31, 2014, margin from off-system sales was $7.8 million, compared to $7.2 million in 2013 and $5.7 million in 2012. 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 are shared equally with customers. Results for the periods presented reflect the impact of that sharing. Off-system sales were 651.1 GWh in 2014, compared to 514.4 GWh in 2013, and 336.7 GWh in 2012. The increase in volumes sold for the years presented from the Company's primarily coal-fired generation result from lower costs to generate due to a decrease in coal prices.

Operating Expenses

Other Operating
For the year ended December 31, 2014, Other operating expenses were $354.5 million, and compared to 2013, increased $21.1 million. Costs recovered directly in margin account for $12.4 million of the increase during the year. Excluding these pass through costs, other operating expenses increased $8.7 million in 2014, compared to 2013, primarily associated with an increase in performance-based compensation expense of $5.5 million and increased expenses related to gas system maintenance of $4.3 million largely due to the harsh winter weather in the first half of 2014.

For the year ended December 31, 2013, Other operating expenses increased $23.3 million compared to 2012. Excluding operating expenses recovered through margin, expenses increased $15.9 million, primarily associated with additional maintenance projects that were completed in 2013 of $7.8 million, increased energy delivery expenses of $2.2 million, and an increase in performance-based compensation of $4.1 million.

Depreciation & Amortization
For the year ended December 31, 2014, Depreciation and amortization expense was $203.1 million, compared to $196.4 million in 2013 and $190.0 million in 2012. Results in the periods presented reflect increased utility plant investments placed into service.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $3.0 million in 2014 compared to 2013 and increased $3.8 million in 2013 compared to 2012. The increase in the periods presented was primarily due to higher revenue taxes associated with increased consumption and higher gas costs. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with higher gas utility and electric utility revenues reflected in margin attributable to regulatory expense recovery mechanisms.

Other Income-Net

Other income-net reflects income of $16.8 million in 2014, compared to $10.5 million in 2013 and $8.0 million in 2012. Results include increased allowance for funds used during construction (AFUDC) of approximately $7.5 million in 2014 compared to 2013 and $1.9 million in 2013 compared to 2012. The higher AFUDC reflects an increased AFUDC rate as well as increased capital expenditures related to infrastructure replacement investments.

Interest Expense

For the year ended December 31, 2014, Interest expense was $66.6 million, compared to $65.0 million in 2013 and $71.5 million in 2012. The decrease in interest expense since 2012 is due to refinancing activity, yielding favorable interest rates. During 2013, Utility Holdings issued $385.9 million in utility related long-term debt with a weighted average interest rate of 3.59 percent and retired $337.9 million of long-term debt that matured or was called for early redemption with a weighted average interest rate of 5.58 percent.

Income Taxes

For the year ended December 31, 2014, Utility Holdings' federal and state income taxes were $83.2 million, compared to $85.3 million in both 2013 and 2012. The lower effective income tax rate in 2014 was primarily driven by the revaluation of Utility Holdings' deferred income taxes related to Vectren's sale of Vectren Fuels, Inc. as well as a tax deduction for domestic production activity in 2014.

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 that 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 in both Indiana and Ohio were passed that 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, 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 and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs is 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. By allowing for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

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 recognized in the Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2014 and 2013, the Company has regulatory assets totaling $16.4 million and $12.1 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 filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms
On August 27, 2014, the Commission issued an Order approving the Company's seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. 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 associated with pipeline safety rules, with 80 percent of the costs 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 update the seven-year capital investment plan annually, with detailed estimates provided for the upcoming calendar year. Finally, the Order approved the Company's proposal to recover eligible costs via a fixed monthly charge per residential customer. On September 26, 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. On January 28, 2015, the OUCC filed its appellate brief raising an issue regarding the treatment of retired assets within the recovery mechanism. An appeal was also filed in response to the IURC's Order in Northern Indiana Public Service Company's (NIPSCO) Senate Bill 560 electric infrastructure proceeding, pertaining to certain issues regarding the Commission's authority to approve NIPSCO's infrastructure plan. The outcome of neither appeal and the implications to the Company's Order, if any, cannot be determined.

On January 14, 2015, the Commission issued an Order approving the Company's initial request for recovery of the revenue requirement associated with capital investment and applicable operating costs through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the Commission approved the Company's update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost increases. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with pipeline safety rules.

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 to be earned 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. To date, the Company has made capital investments under this rider totaling $150.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $13.1 million and $9.3 million at December 31, 2014 and December 31, 2013, respectively. 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 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 Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million, subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On August 27, 2014 the PUCO issued an Order approving the Company’s revised DRR rates and charges, effective September 1, 2014.

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 file a general rate case for the inclusion in rate base of the above costs near 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 three-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 December 31, 2014, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014. During 2014 and 2013, these approved capital expenditure programs under House Bill 95 generated Other income associated with the debt-related post-in-service carrying costs totaling $3.9 million and $2.2 million, respectively. Deferral of depreciation and property tax expenses related to these programs in 2014 and 2013 totaled $3.1 million and $1.7 million, respectively.

Other Regulatory Matters

Indiana Gas GCA Cost Recovery Issue

On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC has modified its position in testimony filed on November 5, 2014, and now suggests a reduced disallowance of $3 million. The Commission has moved this specific issue to a sub-docket proceeding, and based on the procedural schedule, an order is expected later in 2015. The Company believes that the costs are either recoverable in its GCA, or that if the incentive mechanism calculation is found to create a credit due to customers, any such outcome would be funded by its supply administrator. The administrator has intervened and filed testimony in the proceeding.

Indiana Gas & SIGECO Gas Decoupling Extension Filing

On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. On March 2, 2015, the

Company and the OUCC filed a joint settlement agreement for approval by the Commission to extend the decoupling mechanism through 2020.

Electric Rate and Regulatory Matters

SIGECO Electric Environmental Compliance Filing
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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. Although the Company and the Commission acknowledge that these investments are recoverable as clean coal technology under Senate Bill 29 and federal mandated investment under Senate Bill 251, the Order approves the Company’s request for deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. 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 expected to occur in 2015 and 2016.

Coal Procurement Procedures
Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the Commission determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a 6 year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer’s rates effective February 1, 2012. The total balance deferred for recovery through the Company’s FAC, which began February 2014, was $42.4 million, of which $35.3 million remains as of December 31, 2014.

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; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the twelve months ended December 31, 2014 and December 31, 2013, the Company recognized Electric utility revenue of $8.7 million and $5.0 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's December 2009 Order. 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. Indiana's governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the Commission issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015.

FERC Return on Equity (ROE) Complaint

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 MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity 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. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of December 31, 2014, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $143.6 million at December 31, 2014.

This joint complaint is 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 methodology set out in its June 19, 2014 decision.

In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. As of January 2015, a settlement was not reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which will define a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order from the FERC is unknown at this time. The Company has established a reserve pending the outcome of this complaint.

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 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.

Environmental Matters

The Company's 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/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, Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO's electric operations.

Indiana Senate Bill 251

Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations. The Company continues with its ongoing evaluation of the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality

Cross-State Air Pollution Rule

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOX emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2 and NOX allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA finalized a new deadline schedule for entities that must comply, with CSAPR's first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

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. Reductions are to be achieved within three years of publication of the final rule in the Federal Register (April 2015). The EPA did not grant blanket compliance extensions but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Legal challenges to the MATS Rule continue. In July, a coalition of twenty-one states, including Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. On November 25, 2014, the U.S. Supreme Court agreed to hear the case, with a decision expected later in 2015.

Notice of Violation for A.B. Brown Power Plant

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that 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. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Information Request

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the information request.

Ozone NAAQS

On November 26, 2014, the U.S. 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. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may 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.

Water

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. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. The EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 however the rule is not yet finalized. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water Regulations

To comply with Indiana’s implementation plan of the Clean Air Act, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC. SCR technology is the most effective method of reducing NOX emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO’s electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO’s coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOX.

Utilization of the Company’s NOX and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations.

In December 2014 the U.S. EPA released its final coal ash rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). At this time the final rule has not been published in the Federal Register and as such is not yet effective. Under the final rule the Company will be required to commence an enhanced groundwater monitoring program to determine whether its existing ash ponds must be closed or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to beneficially reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states in lieu of citizen suits.

The Company originally estimated capital expenditures to comply with the alternatives in the proposal could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives was selected. As the less stringent Subtitle D program was selected by U.S. EPA in the final rule, the Company expects capital expenditures to comply in the lower end of this range. Annual compliance costs could increase only slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change
As a wholly owned subsidiary of Vectren, Utility Holdings 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 base load generation including effective energy conservation, demand side management, and generation efficiency measures;
- Inclusion of incentives for investment in advanced clean coal technology and support for research and development; 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:
- 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 conservation initiatives in the Company’s Indiana and Ohio gas utility service territories;
- Implementing conservation and demand side management initiatives in the electric service territory;
- Building a renewable energy portfolio to complement base load generation in advance of mandated renewable energy portfolio standards;

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- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans; and
- Reducing the Company's carbon footprint by measures such as utilizing hybrid vehicles and optimizing generation efficiencies by utilizing dense pack technology.

In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized two sets of GHG regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal-fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO2 emissions by 30 percent from 2005 levels by 2030. The EPA provided an extended time frame for public commentary to December 1, 2014. The proposal sets state-specific CO2 emission rate-based CO2 goals (measured in lb CO2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO2/MWh, and sets an interim goal of 1,607 lb CO2/MWh and a final emission goal of 1,531 lb CO2/MWh that must be met by 2030. Under this proposal, these CO2 emission rate goals do not apply directly to individual units, or generating systems. They instead are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state's interim or "phase in" goal of 1,607 lb CO2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal, all states have unique goals based upon each state's mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana's total CO2 emission rate compared to 2012. At 20 percent, Indiana's CO2 emission rate reduction requirement is tied with West Virginia as the 9^{th} lowest reduction requirement. This is due in part to the EPA's attempt to recognize the existing generating resource mix in the state and take into account each state's ability to cost effectively lower its CO2 emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA's determination of "Best System of Emission Reductions that has been adequately demonstrated," which defines the EPA's authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state's existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO_2 emission rate. The Company timely filed comments to the Clean Power Plan proposal on December 1, 2014. The state of Indiana also filed public comments, asking that the proposal be withdrawn. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of

Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans. That litigation has been set for argument before the U.S. Court of Appeals for the D.C. circuit in April of 2015, with a decision expected later in the summer.

With respect to the state of Indiana, the four building blocks that support Indiana’s goal are as follows:
(1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
(3) Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
(4) Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO_2 emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana’s electric utilities generated 105.6 million tons of CO_2. The Company’s share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company’s emissions of CO_2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. 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 clean energy sources 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 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company’s CO_2 emission rate of 1922 lbs/MWh is basically the same as the State’s average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown
If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO_2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company’s fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, 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. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will continue to remain engaged with the state to develop a plan for compliance and have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

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 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 to date approximately $14.3 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of December 31, 2014 and 2013, approximately $3.6 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Impact of Recently Issued Accounting Guidance

Revenue Recognition 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 and IFRS. 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. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements.
Financial Reporting of Discontinued Operations
In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company did not early adopt this guidance in accounting for the sale of its Coal Mining assets. The Company is currently evaluating the impact of this guidance, if any.

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016, and for annual and interim periods thereafter, with early application permitted. Adoption of this guidance will not have a material impact on the Company's financial statements.

Critical Accounting Policies

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

Goodwill

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

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

Intercompany Allocations

Support Services
Vectren provides corporate, general, and administrative services to the Company and allocates costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs have been allocated using various allocators, including number of employees, number of customers, and/or the level of payroll, revenue contribution, and capital expenditures. Allocations are at cost. Management believes that the allocation methodology is reasonable and approximates the costs that would have been incurred had the Company secured those services on a stand-alone basis. The allocation methodology is not subject to near term changes.

Pension and Other Postretirement Obligations
Vectren satisfies the future funding requirements of its pension and other postretirement plans and the payment of benefits from general corporate assets and, as necessary, relies on Utility Holdings to support the funding of these obligations. However, Utility Holdings has no contractual funding commitment. Vectren allocates the periodic cost

of its retirement plans calculated pursuant to US GAAP to its subsidiaries. Periodic cost, comprised of service cost and interest on that service cost, is directly charged to Utility Holdings based on labor at each measurement date and that cost is charged to operating expense and capital projects, using labor charges as the allocation method. Other components of periodic costs (such as interest cost, asset returns, and amortizations) and the service cost related to Vectren Corporate operations are charged to subsidiaries through the allocation process discussed above. Any difference between funding requirements and allocated periodic costs is recognized as an asset or liability until reflected in periodic costs. Neither plan assets nor the ending liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. Management believes these direct charges when combined with benefit-related corporate charges discussed in “support services” above approximate costs that would have been incurred if the Company accounted for benefit plans on a stand-alone basis.

Vectren estimates the expected return on plan assets, discount rate, rate of compensation increase, and future health care costs, among other inputs, and obtains actuarial estimates to assess the future potential liability and funding requirements of pension and postretirement plans. Vectren used the following weighted average assumptions to develop 2014 periodic benefit cost: a discount rate of approximately 4.74 percent, an expected return on plan assets of 7.75 percent, a rate of compensation increase of 3.50 percent, and an inflation assumption of 2.75 percent. Due to higher interest rates, the discount rate is 70 basis points higher from the assumption used in 2013. The rate of return and inflation rates remained the same from 2013 to 2014. To estimate 2015 costs, the following weighted average assumptions were used: a discount rate of approximately 4.05 percent; an expected return on plan assets of 7.50 percent; a rate of compensation increase of 3.50 percent; and an inflation assumption of 2.50 percent. Further, at December 31, 2014, management updated its base mortality assumption to the Society of Actuaries (SOA) 2014 table as well as updated its projected mortality improvement. Future changes in health care costs, work force demographics, interest rates, asset values or plan changes could significantly affect the estimated cost of these future benefits. Vectren’s management currently estimates a pension and postretirement cost of approximately $9 million in 2015, compared to approximately $6 million in 2014, $14 million in 2013, and $12 million in 2012.

Vectren’s management estimates that a 50 basis point increase in the discount rate used to estimate retirement costs generally decreases periodic benefit cost by approximately $2.0 million.

Regulation

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

Financial Condition

Utility Holdings funds the short-term and long-term financing needs of its utility subsidiary operations. Vectren does not guarantee Utility Holdings' debt. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. The guarantees are full and unconditional and joint and several, and Utility Holdings has no subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 14 to the consolidated financial statements. Utility Holdings' long-term debt and short-term obligations outstanding at December 31, 2014 approximated $875 million and $156 million, respectively. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at December 31, 2014 was $382 million.

Utility Holdings' operations have historically been the primary source for Vectren's common stock dividends.

The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at December 31, 2014, are A-/A2 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (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. On January 30, 2014, Moody's upgraded the senior unsecured credit ratings of Utility Holdings and Indiana Gas from A3 to A2. In addition, Utility Holdings' commercial paper was upgraded to P-1 from P-2, and SIGECO's senior secured debt was upgraded to Aa3 from A1. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 50-60 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 54 percent and 53 percent of long-term capitalization at December 31, 2014 and 2013, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders' equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of December 31, 2014, the Company was in compliance with all debt covenants.

Available Liquidity

The Company's A-/A2 investment grade credit ratings have allowed it to access the capital markets as needed, and the Company believes it will have the ability to continue to do so. Given the Company's intent to maintain a balanced long-term capitalization ratio, it anticipates funding future capital expenditures and dividends principally through internally generated funds, supplemented with incremental external debt financing. However, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline infrastructure replacement; and expanded EPA regulations for air, water, and fly ash. These regulations may result in the need to raise additional capital in the coming years.

The Company routinely seeks approval at the IURC and the PUCO for long-term financing authority at the individual utility level. This authority provides for the flexibility for each utility to issue its own debt and equity securities to third parties or to issue its debt and equity securities to the Company and thus receive some of the proceeds from various Company issuances to third parties on the same terms as those obtained by the Company. It is expected that the majority of the long-term debt needs of the utilities will be met through these debt issuances by the Company, some or all of which are then reloaned to the individual utilities. The most recent financing orders for SIGECO and IGC were received from the IURC on March 5, 2015. A similar request for long-term financing authority for VEDO is pending before the PUCO and an order is also expected in March 2015.

On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear interest at 4.00 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1, 2025, sold in a private placement at variable rates through September 2019.

Consolidated Short-Term Borrowing Arrangements

At December 31, 2014, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2014, approximately $194 million was available. This short-term credit facility was amended on October 31, 2014 to extend its maturity until October 2019. The maximum limit of the facility remained unchanged. This facility is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis.

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

(In millions)	2014	2013	2012
Year End			
Balance Outstanding	$156.4	$28.6	$116.7
Weighted Average Interest Rate	0.50 %	0.29 %	0.40 %
Annual Average			
Balance Outstanding	$35.6	$119.6	$77.6
Weighted Average Interest Rate	0.34 %	0.34 %	0.47 %
Maximum Month End Balance Outstanding	$156.4	$176.1	$214.2

Throughout 2014, 2013, and 2012, the Company placed commercial paper without any significant issues and did not borrow from its backup credit facility in any of these periods.

Proceeds from Stock Plans

Vectren may periodically issue new common shares to satisfy dividend reinvestment plan and other employee benefit plan requirements and contribute those proceeds to Utility Holdings. New issuances in 2014, 2013, and 2012 contributed to Utility Holdings added additional liquidity of $6.0 million, $6.1 million and $7.0 million, respectively.

Potential Uses of Liquidity

Planned Capital Expenditures

During 2014, capital expenditures approximated $350 million, compared to $260 million in 2013 and $250 million in 2012. Planned capital expenditures, including contractual purchase commitments, for the five-year period 2015 – 2019 are expected to total approximately (in millions): $405, $395, $360, $355, and $380, respectively. This plan contains the best estimate of the resources required for known regulatory compliance; however, many environmental and pipeline safety standards are subject to change in the near term. Such changes could materially impact planned capital expenditures.

Pension and Postretirement Funding Obligations

As of December 31, 2014, Vectren's assets related to its qualified pension plans were approximately 87 percent of the projected benefit obligation on a GAAP basis and 108 percent of the target liability for ERISA purposes. Vectren's management has made contributions of $20 million to qualified pension plans in 2015.

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2014:

	Total	2015	2016	2017	2018	2019	Thereafter
Long-term debt (1)	$1,257.3	$95.0	$13.0	$—	$100.0	$—	$1,049.3
Short-term debt	156.4	$156.4	—	—	—	—	—
Long-term debt interest commitments	841.0	62.1	56.6	56.1	53.7	50.3	562.2
Plant purchase commitments	0.6	0.2	0.2	0.2	—	—	—
Operating leases	6.1	0.9	0.8	0.8	0.7	0.5	2.4
Total (2)	$2,261.4	$314.6	$70.6	$57.1	$154.4	$50.8	$1,613.9

(1) The debt due in 2015 is comprised of debt issued by Indiana Gas and Utility Holdings

(2) The Company has other long-term liabilities that total approximately $109 million. This amount is comprised of the following: allocated portions of Vectren's deferred compensation and share-based compensation $36 million, asset retirement obligations $54 million, allocated portions of Vectren's postretirement obligations totaling $11 million, investment tax credits $3 million, environmental remediation $4 million, and other obligations including unrecognized tax benefits totaling $1 million. Based on the nature of these items their expected settlement dates cannot be estimated.

The Company's regulated utilities have both firm and non-firm commitments to purchase natural gas, coal, and electricity as well as certain transportation and storage rights. 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. Because of the pass through nature of these costs, they have not been included in the listing of contractual obligations.

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 $337.5 million in 2014, compared to $399.9 million in 2013 and $373.4 million in 2012. The $61.7 million decrease in operating cash flow in 2014 compared to 2013 is primarily driven by changes in certain working capital accounts, specifically higher coal inventory levels at December 31, 2014 primarily driven by weather variations in the year as well as an increase in prepaid taxes due to the timing in which federal legislation was passed to extend bonus depreciation.

In 2013, operating cash flows increased $26.5 million compared to 2012. This increase was primarily due to a greater level of cash from working capital accounts in 2013 as compared to 2012 mostly due to higher inventories at SIGECO and an increase in accounts receivable in 2012. The change in noncurrent assets was primarily driven by the deferral for future recovery of certain coal costs pursuant to a regulatory order in the prior year.

Tax payments in 2013 and 2012 were favorably impacted by federal legislation extending bonus depreciation. The increase in prepaid taxes in 2014 was due to the timing of the passage of this legislation to extend bonus depreciation retroactively for the year. Federal legislation allowing bonus depreciation on qualifying capital expenditures was 50 percent for each of the years 2012, 2013, and 2014. A significant portion of the Company's capital expenditures qualified for this bonus treatment.

Financing Cash Flow

Net cash from financing activities for the year ended December 31, 2014 was an inflow of $23.9 million while cash flow from financing activities for the years ended December 31, 2013 and 2012 were outflows of $142.9 million and $121.1 million, respectively. Financing activity reflects the Company's utilization of the long-term capital markets in the current low interest rate environment. For the three years ended December 31, 2014, the Company has issued $549 million in long-term debt, of which $497 million was used to refinance maturing or called long-term debt and $52 million was used to meet its incremental debt financing requirements. The lower rates achieved have favorably impacted interest expense throughout the periods presented. The Company's operating cash flow funded 73 percent of capital expenditures and dividends in 2014, and over 100 percent of capital expenditures and dividends in 2013 and 2012. Recently completed long-term financing transactions are more fully described below.

SIGECO Debt Refund and Issuance

On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear interest at 4.00 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1, 2025, sold in a private placement at variable rates through September 2019.

SIGECO 2013 Debt Refund and Reissuance

During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95 percent per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

Utility Holdings 2013 Debt Call and Reissuance

On April 1, 2013, VUHI exercised a call option at par on $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012 with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8 million and $79.6 million, respectively. The notes are unconditionally guaranteed by SIGECO, Indiana Gas, and VEDO.

On August 22, 2013, VUHI entered into a private placement note purchase agreement with a delayed draw feature, pursuant to which institutional investors agreed to purchase $150 million of senior guaranteed notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The notes were unconditionally guaranteed by SIGECO, Indiana Gas, and VEDO. On December 5, 2013, the Company received net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which were used to refinance $100 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes.

Utility Holdings 2012 Debt Transactions

On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements.

Mandatory Tenders

At December 31, 2014, certain series of SIGECO bonds, aggregating $49.1 million, currently bear interest at fixed rates and are subject to mandatory tender in September 2017. Additionally, SIGECO Bond Series 2014B, in the amount of $41.3 million, with a variable interest rate that is reset monthly, is subject to mandatory tender in September 2019.

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Investing Cash Flow

Cash flow required for investing activities was $350.7 million in 2014, $261.7 million in 2013, and $245.0 million in 2012. The primary use of cash in all years reflects expenditures for utility plant. The increase in Utility Holdings' capital expenditures in 2014 over 2013 is attributable to greater expenditures for gas infrastructure improvement projects and environmental compliance.

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 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.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, 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 unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under regulation, 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; impacts on both gas and electric large customers; lower residential and commercial customer counts; and higher operating expenses.
- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Volatile oil prices and the potential impact on customer consumption and price of other fuel commodities.
- Direct or indirect effects on the Company’s business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.

- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part

of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.

- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with federal and state laws and interpretations of these laws.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

The Company 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.

Commodity Price Risk

Regulated Operations

The Company's regulated operations have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal and purchased power for the benefit of retail customers due to current state regulations, which subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. Constructive regulatory orders, such as those authorizing lost margin recovery, other innovative rate designs, and recovery of unaccounted for gas and other gas related expenses, also mitigate the effect volatile gas costs may have on the Company's financial condition. Although the Company's regulated operations are exposed to limited commodity price risk, volatile natural gas and coal prices have other effects on working capital requirements, interest costs, and some level of price-sensitivity in volumes sold or delivered. Indiana Gas and SIGECO hedge up to 50 percent of annual gas purchases for each Company via the use of physical 5 year and 10 year fixed-price purchases and financial products, including call options.

Wholesale Power Marketing

The Company's wholesale power marketing activities undertake strategies to optimize electric generating capacity beyond that needed for native load. In recent years, the primary strategy involves the sale of generation into the MISO Day Ahead and Real-time markets. The Company accounts for any energy contracts that are derivatives at fair value with the offset marked to market through earnings. No derivative positions were outstanding on December 31, 2014 and 2013.

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

Interest Rate Risk

The Company is exposed to interest rate risk associated with its borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on interest expense. The Company limits this risk by allowing only an annual average of 15 percent to 25 percent of its total debt to be exposed to variable rate volatility. This targeted range may not always be attained during the seasonal increases in short-term borrowings. To further manage this exposure, the Company may also use derivative financial instruments.

Market risk is estimated as the potential impact resulting from fluctuations in interest rates on adjustable rate borrowing arrangements on both short-term borrowings and long term debt exposed to short-term interest rate volatility. During 2014 and 2013, the weighted average combined borrowings under these arrangements approximated $77 million and $161 million, respectively. At December 31, 2014, combined borrowings under these arrangements were $198 million. As of December 31, 2013 combined borrowings under these arrangements were $69 million. Based upon average borrowing rates under these facilities during the years ended December 31, 2014 and 2013, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by approximately $0.8 million in 2014 and $1.6 million in 2013.

Other Risks

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT’S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

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

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

These consolidated financial statements are also subject to an evaluation of internal control over financial reporting conducted under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer. Based on that evaluation, conducted under the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, the Company concluded that its internal control over financial reporting was effective as of December 31, 2014. Management certified this in its Sarbanes Oxley Section 302 certifications, which are filed as exhibits to this 2014 Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Vectren Utility Holdings, Inc. and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Vectren Utility Holdings, Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 5, 2015

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

	At December 31,	
	2014	2013
ASSETS		
Current Assets		
Cash & cash equivalents	$19.3	$8.6
Accounts receivable - less reserves of $3.9 & $5.0, respectively	113.0	112.1
Accrued unbilled revenues	122.4	113.5
Inventories	113.2	89.9
Recoverable fuel & natural gas costs	9.8	5.5
Prepayments & other current assets	83.5	42.4
Total current assets	461.2	372.0
Utility Plant		
Original cost	5,718.7	5,389.6
Less: accumulated depreciation & amortization	2,279.7	2,165.3
Net utility plant	3,439.0	3,224.3
Investments in unconsolidated affiliates	0.2	0.2
Other investments	25.6	27.3
Nonutility plant - net	149.2	150.5
Goodwill	205.0	205.0
Regulatory assets	128.3	136.2
Other assets	19.6	25.3
TOTAL ASSETS	$4,428.1	$4,140.8

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

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

	At December 31,	
	2014	2013
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$180.4	$172.1
Payables to other Vectren companies	28.6	24.6
Accrued liabilities	122.3	127.4
Short-term borrowings	156.4	28.6
Current maturities of long-term debt	95.0	—
Total current liabilities	582.7	352.7
Long-Term Debt - Net of Current Maturities	1,162.3	1,257.1
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	685.1	627.4
Regulatory liabilities	410.3	387.3
Deferred credits & other liabilities	109.2	83.5
Total deferred credits & other liabilities	1,204.6	1,098.2
Commitments & Contingencies (Notes 8-11)		
Common Shareholder's Equity		
Common stock (no par value)	793.7	787.7
Retained earnings	684.8	645.1
Total common shareholder's equity	1,478.5	1,432.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,428.1	$4,140.8

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

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

	Year Ended December 31,		
	2014	2013	2012
OPERATING REVENUES			
Gas utility	$944.6	$810.0	$738.1
Electric utility	624.8	619.3	594.9
Other	0.3	0.3	0.6
Total operating revenues	1,569.7	1,429.6	1,333.6
OPERATING EXPENSES			
Cost of gas sold	468.7	358.1	301.3
Cost of fuel & purchased power	201.8	202.9	192.0
Other operating	354.5	333.4	310.1
Depreciation & amortization	203.1	196.4	190.0
Taxes other than income taxes	60.2	57.2	53.4
Total operating expenses	1,288.3	1,148.0	1,046.8
OPERATING INCOME	281.4	281.6	286.8
Other income - net	16.8	10.5	8.0
Interest expense	66.6	65.0	71.5
INCOME BEFORE INCOME TAXES	231.6	227.1	223.3
Income taxes	83.2	85.3	85.3
NET INCOME	$148.4	$141.8	$138.0

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

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

	Year Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$148.4	$141.8	$138.0
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	203.1	196.4	190.0
Deferred income taxes & investment tax credits	55.7	26.4	72.3
Expense portion of pension & postretirement periodic benefit cost	4.7	5.6	5.0
Provision for uncollectible accounts	6.1	6.5	7.4
Other non-cash expense	3.2	2.5	5.6
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenue	(15.8)	(56.8)	3.7
Inventories	(23.3)	24.1	18.5
Recoverable/refundable fuel & natural gas costs	(4.4)	22.4	(12.9)
Prepayments & other current assets	(34.4)	15.5	2.6
Accounts payable, including to Vectren companies & affiliated companies	7.5	10.1	(7.4)
Accrued liabilities	(2.2)	4.9	(1.6)
Changes in noncurrent assets	6.4	11.4	(33.2)
Changes in noncurrent liabilities	(17.5)	(10.9)	(14.6)
Net cash flows from operating activities	337.5	399.9	373.4
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt - net of issuance costs	62.4	381.7	99.5
Additional capital contribution	6.0	6.1	7.0
Requirements for:			
Dividends to parent	(108.7)	(105.1)	(101.5)
Retirement of long-term debt	(63.6)	(337.5)	—
Net change in short-term borrowings	127.8	(88.1)	(126.1)
Net cash flows from financing activities	23.9	(142.9)	(121.1)
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from other investing activities	0.3	0.8	2.6
Requirements for:			
Capital expenditures, excluding AFUDC equity	(351.0)	(262.5)	(247.6)
Net cash flows from investing activities	(350.7)	(261.7)	(245.0)
Net change in cash & cash equivalents	10.7	(4.7)	7.3
Cash & cash equivalents at beginning of period	8.6	13.3	6.0
Cash & cash equivalents at end of period	$19.3	$8.6	$13.3

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

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

	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance at January 1, 2012	$774.6	$572.0	$—	$1,346.6
Net income		138.0		138.0
Other comprehensive income				—
Common stock:				
Additional capital contribution	7.0			7.0
Dividends		(101.5)		(101.5)
Other		(0.1)		(0.1)
Balance at December 31, 2012	781.6	608.4	—	1,390.0
Net income		141.8		141.8
Common stock:				
Additional capital contribution	6.1			6.1
Dividends		(105.1)		(105.1)
Balance at December 31, 2013	787.7	645.1	—	1,432.8
Net income		148.4		148.4
Common stock:				
Additional capital contribution	6.0			6.0
Dividends		(108.7)		(108.7)
Balance at December 31, 2014	$793.7	$684.8	$—	$1,478.5

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

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

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (the Company, Utility Holdings or VUHI), an Indiana corporation, was formed on March 31, 2000, to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), Southern Indiana Gas and Electric Company (SIGECO), 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. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana, and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 575,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 electric customers and over 110,000 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 313,000 natural gas customers located near Dayton in west central Ohio.

2. Summary of Significant Accounting Policies

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

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

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

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

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

Inventories
In most circumstances, the Company’s inventory components are recorded using an average cost method; however, natural gas in storage at the Company’s Indiana utilities is recorded using the Last In – First Out (LIFO) method. Inventory is valued at

historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

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

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

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

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

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

Impairment Reviews
Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review involves the comparison of an asset's (or group of assets') carrying value to the estimated future cash flows the asset (or asset group) is expected to generate over a remaining life. If this evaluation were to conclude that the carrying value is impaired, an impairment charge would be recorded based on the difference between the carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations. There were no impairments related to property, plant and equipment during the periods presented.

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

Regulation

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

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

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

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

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

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

When an energy contract, that is a derivative, is designated and documented as a normal purchase or normal sale (NPNS), it is exempted from mark-to-market accounting. Most energy contracts executed by the Company are subject to the NPNS exclusion or are not considered derivatives. Such energy contracts include Real Time and Day Ahead purchase and sale contracts with the MISO, natural gas purchases, and wind farm and other electric generating contracts.

When the Company engages in energy contracts and financial contracts that are derivatives and are not subject to the NPNS or other exclusions, such contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and on when the contracts are expected to be settled. Contracts and any associated collateral with counter-parties subject to master netting arrangements are presented net in the Consolidated Balance Sheets. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to regulatory accounting treatment. When hedge accounting is appropriate, the Company assesses and documents hedging relationships between the derivative contract and underlying risks as well as its risk management objectives and anticipated effectiveness. When the hedging relationship is highly effective, derivatives are designated as hedges. The market value of the effective portion of the hedge is marked to market in Accumulated other comprehensive income for cash flow hedges. Ineffective portions of hedging arrangements are marked to market through earnings. For fair value hedges, both the derivative and the underlying hedged item are marked to market through earnings. The offset to contracts affected by regulatory accounting treatment are marked to market as a regulatory asset or liability. Market value for derivative contracts is determined using quoted market prices from independent sources. The Company rarely enters into contracts that have a significant impact to the financial statements where internal models are used to calculate fair value. As of and for the periods presented, related derivative activity is not material to these financial statements.

Revenues

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

MISO Transactions

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

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

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

Excise & Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $32.3 million in 2014, $29.6 million in 2013, and $26.9 million in 2012. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

Operating Segments

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

Fair Value Measurements

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

Level 1	Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets.
Level 2	Inputs to the valuation methodology include · quoted prices for similar assets or liabilities in active markets; · quoted prices for identical or similar assets or liabilities in inactive markets; · inputs other than quoted prices that are observable for the asset or liability; · inputs that are derived principally from or corroborated by observable market data by correlation or other means If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.
Level 3	Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

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

Earnings Per Share
Earnings per share are not presented as Utility Holdings' common stock is wholly owned by Vectren.

Other Significant Policies
Included elsewhere in these notes are significant accounting policies related to retirement plans and other postretirement benefits, intercompany allocations and income taxes (Note 5).

3. Utility & Nonutility Plant

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

	At and For the Year Ended December 31,					
(In millions)	2014			2013		
	Original Cost	Depreciation Rates as a Percent of Original Cost		Original Cost	Depreciation Rates as a Percent of Original Cost	
Gas utility plant	$3,011.0	3.4	%	$2,762.2	3.5	%
Electric utility plant	2,602.5	3.3	%	2,519.8	3.3	%
Common utility plant	54.3	3.2	%	53.4	3.0	%
Construction work in progress	50.9	—		54.2	—	
Total original cost	$5,718.7			$5,389.6		

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own the 300 MW Unit 4 at the Warrick Power Plant as tenants in common. SIGECO's share of the cost of this unit at December 31, 2014, is $188.0 million with accumulated depreciation totaling $93.5 million. AGC and SIGECO also share equally in the cost of operation and output of the unit. SIGECO's share of operating costs is included in Other operating expenses in the Consolidated Statements of Income.

Nonutility Plant, net of accumulated depreciation and amortization follows:

	At December 31,	
(In millions)	2014	2013
Computer hardware & software	$105.0	$102.3

Land & buildings	35.8	38.3
All other	8.4	9.9
Nonutility plant - net	$149.2	$150.5

Nonutility plant is presented net of accumulated depreciation and amortization totaling $226.7 million and $209.2 million as of December 31, 2014 and 2013, respectively. For the years ended December 31, 2014, 2013, and 2012, the Company capitalized interest totaling $0.6 million, $0.4 million, and $0.2 million, respectively, on nonutility plant construction projects.

4. Regulatory Assets & Liabilities

Regulatory Assets
Regulatory assets consist of the following:

	At December 31,	
(In millions)	2014	2013
Future amounts recoverable from ratepayers related to:		
Net deferred income taxes (See Note 5)	$(14.8)	$(5.8)
Asset retirement obligations & other	—	2.3
	(14.8)	(3.5)
Amounts deferred for future recovery related to:		
Deferred coal costs (See Note 10)	—	42.4
Cost recovery riders & other	33.3	18.6
	33.3	61.0
Amounts currently recovered in customer rates related to:		
Unamortized debt issue costs & hedging proceeds	33.5	34.6
Demand side management programs	0.6	2.5
Deferred coal costs (See Note 10)	35.3	—
Indiana authorized trackers	25.6	30.8
Ohio authorized trackers	12.7	7.9
Premiums paid to reacquire debt	1.7	2.2
Other base rate recoveries	0.4	0.7
	109.8	78.7
Total regulatory assets	$128.3	$136.2

Of the $109.8 million currently being recovered in customer rates, $0.6 million that is associated with demand side management programs is earning a return. The weighted average recovery period of regulatory assets currently being recovered in base rates, which totals $36 million, is 23 years. The remainder of the regulatory assets are being recovered timely through periodic recovery mechanisms. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable.

Regulatory Liabilities
At December 31, 2014 and 2013, the Company has approximately $410.3 million and $387.3 million, respectively, in Regulatory liabilities. Of these amounts, $373.5 million and $373.0 million relate to cost of removal obligations. The remaining amounts primarily relate to timing differences associated with asset retirement obligations and deferred financing costs.

5. Transactions with Other Vectren Companies and Affiliates

Vectren Infrastructure Services Corporation (VISCO)
VISCO, a wholly owned subsidiary of Vectren, provides underground pipeline construction and repair services. VISCO's customers include Utility Holdings' utilities and fees incurred by Utility Holdings and its subsidiaries totaled $94.0 million in 2014, $54.2 million in 2013, and $46.6 million in 2012. Amounts owed to VISCO at December 31, 2014 and 2013 are included in Payables to other Vectren companies.

Vectren Fuels, Inc.
On August 29, 2014, Vectren closed on a transaction to sell its wholly-owned coal mining subsidiary, Vectren Fuels, Inc. (Vectren Fuels), to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy

Company. Prior to the sale date, SIGECO purchased coal used for electric generation from Vectren Fuels. Amounts purchased for the years ended December 31, 2014, 2013 and 2012, totaled $98.6 million, $103.7 million, and $115.6 million, respectively. No amounts were owed to Vectren Fuels at December 31, 2014 and amounts owed as of December 31, 2013 were included in Payables to other

Vectren companies. After the exit of the coal mining business by Vectren, Sunrise has assumed Vectren Fuels' supply contracts and has also negotiated new contracts for similar quality coal that will result in the Company purchasing most of its coal supply from Sunrise.

ProLiance Holdings, LLC (ProLiance)
Vectren has an investment in ProLiance, a nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy). ProLiance Energy provided services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance Energy's customers included, among others, Vectren's Indiana utilities as well as Citizens' utilities.

The Company had no purchases from ProLiance for resale and for injections into storage for the year ended December 31, 2014, as a result of ProLiance exiting the natural gas marketing business. For the years ended December 31, 2013 and 2012 the Company had purchases totaling $200.5 million, $274.5 million, respectively. Amounts charged by ProLiance for gas supply services were established by supply agreements with each utility. After the exit of the energy marketing business by ProLiance, the Company purchases gas supply from third parties and 84 percent is from a single third party for the year ended December 31, 2014.

Support Services & Purchases
Vectren provides corporate and general and administrative services to the Company and allocates certain costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs are allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. Utility Holdings received corporate allocations totaling $57.0 million, $50.9 million, and $44.8 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Retirement Plans & Other Postretirement Benefits
At December 31, 2014, Vectren maintains three qualified defined benefit pension plans (Vectren Corporation Non-Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan, and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover the Company's eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. Utility Holdings and its subsidiaries comprise the vast majority of the participants and retirees covered by these plans.

Vectren satisfies the future funding requirements and the payment of benefits from general corporate assets and, as necessary, relies on Utility Holdings to support the funding of these obligations. However, Utility Holdings has no contractual funding commitment and did not contribute to Vectren's defined benefit pension plans during 2014 or 2013. The combined funded status of Vectren's plans was approximately 87 percent at December 31, 2014 and 101 percent at December 31, 2013.

Vectren allocates the periodic cost of its retirement plans calculated pursuant to US GAAP to its subsidiaries. Periodic cost, comprised of service cost and interest on that service cost, is directly charged to Utility Holdings based on labor at each measurement date and that cost is charged to operating expense and capital projects, using labor charges as the allocation method. For the years ended December 31, 2014, 2013 and 2012, costs totaling $6.7 million, $8.0 million and $7.2 million, respectively, were directly charged to Utility Holdings. Other components of periodic costs (such as interest cost, asset returns, and amortizations) and the service cost related to Vectren Corporate operations are charged to subsidiaries through the allocation process discussed above. Any difference between funding requirements and allocated periodic costs is recognized as an asset or liability until reflected in periodic costs.

Neither plan assets nor the ending liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. The allocation methodology is consistent with FASB guidance related to “multiemployer” benefit accounting. As of December 31, 2014 and 2013, $11.6 million and $11.2 million, respectively, is included in Deferred credits & other liabilities and represents costs directly charged to the Company that is yet to be funded to Vectren. As impacted by

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increased funding of pension plans, at December 31, 2014 and 2013, the Company has $17.3 million, and $23.6 million, respectively, included in Other Assets representing defined benefit funding by the Company that is yet to be reflected in costs.

Share-Based Incentive Plans & Deferred Compensation Plans
Utility Holdings does not have share-based compensation plans separate from Vectren. The Company recognizes its allocated portion of expenses related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash that liability is pushed down to Utility Holdings. As of December 31, 2014 and 2013, $36.1 million and $29.6 million, respectively, is included in Deferred credits & other liabilities and represents obligations that are yet to be funded to Vectren.

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

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

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

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

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
Current:			
Federal	$16.6	$48.0	$6.1
State	10.9	11.0	6.9
Total current taxes	27.5	59.0	13.0
Deferred:			
Federal	57.8	26.8	68.7
State	(1.6)	0.1	4.2
Total deferred taxes	56.2	26.9	72.9
Amortization of investment tax credits	(0.5)	(0.6)	(0.6)
Total income tax expense	$83.2	$85.3	$85.3

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

	Year Ended December 31,		
	2014	2013	2012
Statutory rate	35.0 %	35.0 %	35.0 %
State and local taxes-net of federal benefit	3.3	3.5	3.7
Amortization of investment tax credit	(0.2)	(0.3)	(0.3)
Domestic Production Deduction	(0.9)	—	—
Adjustment of income tax accruals	(0.9)	—	—
All other - net	(0.4)	(0.6)	(0.2)
Effective tax rate	35.9 %	37.6 %	38.2 %

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2014	2013
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$685.0	$627.9
Regulatory assets recoverable through future rates	29.2	22.8
Alternative minimum tax carryforward	(13.3)	(18.5)
Employee benefit obligations	1.0	5.2
Regulatory liabilities to be settled through future rates	(27.5)	(18.7)
Other – net	10.7	8.7
Net noncurrent deferred tax liability	685.1	627.4
Current deferred tax liabilities (assets):		
Deferred fuel costs - net	22.0	22.9
Alternative minimum tax carryforward	(38.1)	(36.4)
General business credit carryforwards	—	(1.2)
Other – net	4.8	9.2
Net current deferred tax liability (asset)	(11.3)	(5.5)
Net deferred tax liability	$673.8	$621.9

At December 31, 2014 and 2013, investment tax credits totaling $2.6 million and $3.2 million, respectively, are included in Deferred credits & other liabilities. At December 31, 2014, the Company has alternative minimum tax carryforwards of $51.4 million, which do not expire.

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Uncertain Tax Positions

The following is a roll forward of the total amount of unrecognized tax benefits for the three years ended December 31, 2014:

(In millions)	2014	2013	2012
Unrecognized tax benefits at January 1	$4.7	$3.7	$11.0
Gross increases - tax positions in prior periods	—	—	0.1
Gross decreases - tax positions in prior periods	(4.7)	(0.2)	(9.3)
Gross increases - current period tax positions	—	1.2	1.9
Settlements	—	—	—
Unrecognized tax benefits at December 31	$—	$4.7	$3.7

Of the change in unrecognized tax benefits during 2014, 2013, and 2012, none impacted the effective rate. The amount of unrecognized tax benefits, which if recognized, that would impact the effective tax rate was zero at December 31, 2014 , 2013, and 2012.

In 2014, the Company recognized income related to a reversal of interest expense previously accrued and net of penalties totaling approximately $0.2 million. In 2013, the Company recognized no expense related to interest and penalties. In 2012, the Company recognized income related to a reversal of interest expense previously accrued and net of penalties totaling approximately $0.7 million. The Company had no accrual for payment of interest and penalties as of December 31, 2014, and $0.2 million for the payment of interest and penalties accrued as of 2013.

The Company and/or certain of its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states. The Internal Revenue Service (IRS) has concluded examinations of the Company's U.S. federal income tax returns for tax years through December 31, 2008. The IRS is currently examining the 2009-2012 federal income tax returns as part of a routine review by the Joint Committee on Taxation. The State of Indiana, the Company's primary state tax jurisdiction, has conducted examinations of state income tax returns for tax years through December 31, 2008. The statutes of limitations for assessment of federal income tax and Indiana income tax have expired with respect to tax years through 2008.

Final Federal Income Tax Regulations

In September 2013, the IRS released final tangible property regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, and will be adopted on the 2014 federal income tax return. The IRS has been working with the utility industry to provide industry specific guidance concerning the deductibility and capitalization of expenditures related to tangible property. The IRS has indicated that it expects to issue updated or new guidance with respect to electric and natural gas transmission and distribution assets during 2015. The Company continues to evaluate the impact adoption of the regulations and industry guidance will have on its consolidated financial statements. As of this date, the Company does not expect the adoption of the regulations to have a material impact on its consolidated financial statements.

Indiana Senate Bill 1

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

6. Borrowing Arrangements

Short-Term Borrowings

At December 31, 2014, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2014, approximately $194 million was available. This short-term credit facility was extended in October 2014 and is available through October 2019. The maximum limit of the facility remained unchanged. This facility is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis. The Company has historically funded the short-term borrowing needs through the commercial paper market and expects to use the short-term borrowing facility in instances where the commercial paper market is not efficient.

Following is certain information regarding these short-term borrowing arrangements:

(In millions)	2014	2013	2012
Year End			
Balance Outstanding	$156.4	$28.6	$116.7
Weighted Average Interest Rate	0.50 %	0.29 %	0.40 %
Annual Average			
Balance Outstanding	$35.6	$119.6	$77.6
Weighted Average Interest Rate	0.34 %	0.34 %	0.47 %
Maximum Month End Balance Outstanding	$156.4	$176.1	$214.2

Throughout 2014, 2013, and 2012, the Company placed commercial paper without any significant issues and did not borrow from its backup credit facility in any of these periods.

Long-Term Debt

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

	At December 31,	
(In millions)	2014	2013
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2015, 5.45%	75.0	75.0
2018, 5.75%	100.0	100.0
2020, 6.28%	100.0	100.0
2021, 4.67%	55.0	55.0
2023, 3.72%	150.0	150.0
2026, 5.02%	60.0	60.0
2028, 3.20%	45.0	45.0
2035, 6.10%	75.0	75.0
2041, 5.99%	35.0	35.0
2042, 5.00%	100.0	100.0
2043, 4.25%	80.0	80.0
Total Utility Holdings	875.0	875.0
SIGECO		
First Mortgage Bonds		
2015, 1985 Pollution Control Series A, current adjustable rate 0.05%, tax exempt, 2013 weighted average: 0.10%	—	9.8
2016, 1986 Series, 8.875%	13.0	13.0
2022, 2013 Series C, 1.95%, tax exempt	4.6	4.6
2024, 2013 Series D, 1.95%, tax exempt	22.5	22.5
2025, 1998 Pollution Control Series A, current adjustable rate 0.05%, tax exempt, 2013 weighted average: 0.10%	—	31.5
2025, 2014 Series B, current adjustable rate 0.722%, tax-exempt	41.3	—
2029, 1999 Series, 6.72%	80.0	80.0
2037, 2013 Series E, 1.95%, tax exempt	22.0	22.0
2038, 2013 Series A, 4.0%, tax exempt	22.2	22.2
2040, 2009 Environmental Improvement Series, 5.40%, tax exempt	—	22.3
2043, 2013 Series B, 4.05%, tax exempt	39.6	39.6
2044, 2014 Series A, 4.00%, tax exempt	22.3	—
Total SIGECO	267.5	267.5
Indiana Gas		
Senior Unsecured Notes		
2015, Series E, 7.15%	5.0	5.0
2015, Series E, 6.69%	5.0	5.0
2015, Series E, 6.69%	10.0	10.0
2025, Series E, 6.53%	10.0	10.0
2027, Series E, 6.42%	5.0	5.0
2027, Series E, 6.68%	1.0	1.0
2027, Series F, 6.34%	20.0	20.0
2028, Series F, 6.36%	10.0	10.0
2028, Series F, 6.55%	20.0	20.0
2029, Series G, 7.08%	30.0	30.0

Total Indiana Gas	116.0	116.0
Total long-term debt outstanding	1,258.5	1,258.5
Current maturities of long-term debt	(95.0)	—
Unamortized debt premium & discount - net	(1.2)	(1.4)
Total long-term debt-net	$1,162.3	$1,257.1

SIGECO Debt Refund and Issuance
On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear interest at 4.00 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1, 2025, sold in a private placement at variable rates through September 2019.

SIGECO 2013 Debt Refund and Reissuance
During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95 percent per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

Utility Holdings 2013 Debt Call and Reissuance
On April 1, 2013, VUHI exercised a call option at par on $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012 with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8 million and $79.6 million, respectively. The notes are unconditionally guaranteed by SIGECO, Indiana Gas, and VEDO.

On August 22, 2013, VUHI entered into a private placement note purchase agreement with a delayed draw feature, pursuant to which institutional investors agreed to purchase $150 million of senior guaranteed notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The notes were unconditionally guaranteed by SIGECO, Indiana Gas, and VEDO. On December 5, 2013, the Company received net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which were used to refinance $100 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes.

Utility Holdings 2012 Debt Transactions
On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings’ regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings’ borrowing arrangements.

Mandatory Tenders
At December 31, 2014, certain series of SIGECO bonds, aggregating $49.1 million, currently bear interest at fixed rates and are subject to mandatory tender in September 2017. Additionally, SIGECO Bond Series 2014B, in the amount of $41.3 million, with a variable interest rate that is reset monthly, is subject to mandatory tender in September 2019.

Future Long-Term Debt Sinking Fund Requirements and Maturities

The annual sinking fund requirement of SIGECO's first mortgage bonds is 1 percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. SIGECO intends to meet the 2014 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2014 is excluded from Current liabilities in the Consolidated Balance Sheets. At December 31, 2014, $1.3 billion of SIGECO's utility plant remained unfunded under

SIGECO's Mortgage Indenture. SIGECO’s gross utility plant balance subject to the Mortgage Indenture approximated $3.0 billion at December 31, 2014.

Consolidated maturities of long-term debt during the years following 2014 (in millions) are $95.0 million in 2015, $13.0 in 2016, $0.0 in 2017, $100.0 in 2018, $0.0 in 2019, and $1,049.3 thereafter.

Debt Guarantees
Utility Holdings’ currently outstanding long-term and short-term debt is jointly and severally guaranteed by SIGECO, Indiana Gas, and VEDO. Utility Holdings’ long-term debt and short-term debt outstanding at December 31, 2014, totaled $875 million and $156 million, respectively.

Covenants
Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of December 31, 2014, the Company was in compliance with all financial covenants.

7. Common Shareholder’s Equity

During the years ended December 31, 2014, 2013, and 2012, the Company has cumulatively received additional capital of $19.1 million from Vectren which was funded by new share issues from Vectren’s dividend reinvestment plan.

8. Commitments & Contingencies

Commitments
Future minimum lease payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year during the five years following 2014 and thereafter (in millions) are $0.9 in 2015, $0.8 in 2016, $0.8 in 2017, $0.7 in 2018, $0.5 in 2019, and $2.4 thereafter. Total lease expense (in millions) was $1.5 in 2014, $1.1 in 2013, and $1.2 in 2012. Firm purchase commitments for utility plant total $0.2 million in 2015, $0.2 million in 2016 and $0.2 million in 2017, and zero thereafter.

The Company’s regulated utilities have both firm and non-firm commitments to purchase natural gas, coal, and electricity as well as certain transportation and storage rights and certain contracts are firm commitments under five and ten year arrangements. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms. Because of the pass through nature of these costs, they have not been included in the listing of contractual obligations.

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

9. Gas Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement

The Company monitors and maintains its natural gas distribution system to ensure that 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 in both Indiana and Ohio were passed that 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, 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 and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs is 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. By allowing for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs until recovery is approved by the Ohio Commission.

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 recognized in the Consolidated Statements of Income currently. The recording of post-in-service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At December 31, 2014 and 2013, the Company has regulatory assets totaling $16.4 million and $12.1 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 filed pursuant to Senate Bill 251, discussed further below.

Requests for Recovery Under Indiana Regulatory Mechanisms
On August 27, 2014, the Commission issued an Order approving the Company’s seven-year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to Senate Bill 251 and 560. 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 associated with pipeline safety rules, with 80 percent of the costs 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 update the seven-year capital investment plan annually, with detailed estimates provided for the upcoming calendar year. Finally, the Order approved the Company's proposal to recover eligible costs via a fixed monthly charge per residential customer. On September 26, 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed a Notice of Appeal with the Indiana Court of Appeals in response to

the IURC's Order. On January 28, 2015, the OUCC filed its appellate brief raising an issue regarding the treatment of retired assets within the recovery mechanism. An appeal was also filed in response to the IURC's Order in Northern Indiana Public Service Company's (NIPSCO) Senate Bill 560 electric infrastructure proceeding, pertaining to certain issues regarding the Commission's authority to approve NIPSCO's infrastructure plan. The outcome of neither appeal and the implications to the Company’s Order, if any, cannot be determined.

On January 14, 2015, the Commission issued an Order approving the Company’s initial request for recovery of the revenue requirement associated with capital investment and applicable operating costs through June 30, 2014 as part of its approved seven-year plan. As the next step of the recovery process, as outlined in the legislation, this Order initiates the rates and charges necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also, consistent with the guidelines set forth in the original August 2014 Order, the Commission approved the Company’s update to its seven-year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost increases. The updated plan reflects capital expenditures of approximately $900 million, an increase of $35 million from the previous plan and is inclusive of an estimated $30 million of economic development related expenditures, over the seven-year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with pipeline safety rules.

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 to be earned 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. To date, the Company has made capital investments under this rider totaling $150.5 million. Regulatory assets associated with post-in-service carrying costs and depreciation deferrals were $13.1 million and $9.3 million at December 31, 2014 and December 31, 2013, respectively. 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 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 Company's five-year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million, subject to the graduated caps on the fixed DRR monthly charge applicable to residential and small general service customers approved in the Order. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On August 27, 2014 the PUCO issued an Order approving the Company’s revised DRR rates and charges, effective September 1, 2014.

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 file a general rate case for the inclusion in rate base of the above costs near 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 three-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 December 31, 2014, the Company's deferrals have not reached this bill impact cap. In addition, the Orders approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014. During 2014 and 2013, these approved capital expenditure programs under House Bill 95 generated Other income associated with the debt-related post-in-service carrying costs totaling $3.9 million and $2.2 million, respectively. Deferral of depreciation and property tax expenses related to these programs in 2014 and 2013 totaled $3.1 million and $1.7 million, respectively.

Other Regulatory Matters
Indiana Gas GCA Cost Recovery Issue
On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the OUCC filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC has modified its position in testimony filed on November 5, 2014, and now suggests a reduced disallowance of $3 million. The Commission has moved this specific issue to a sub-docket proceeding, and based on the procedural schedule, an order is expected later in 2015. The Company believes that the costs are either recoverable in its GCA, or that if the incentive mechanism calculation is found to create a credit due to customers, any such outcome would be funded by its supply administrator. The administrator has intervened and filed testimony in the proceeding.

Indiana Gas & SIGECO Gas Decoupling Extension Filing
On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both Indiana gas companies and recovery of new conservation program costs through December 2015. On March 2, 2015, the Company and the OUCC filed a joint settlement agreement for approval by the Commission to extend the decoupling mechanism through 2020.

10. Electric Rate & Regulatory Matters

SIGECO Electric Environmental Compliance Filing
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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions. Although the Company and the Commission acknowledge that these investments are recoverable as clean coal technology under Senate Bill 29 and federal mandated investment under Senate Bill 251, the Order approves the Company’s request for deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. 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 expected to occur in 2015 and 2016.

Coal Procurement Procedures
Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure its supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to Sunrise Coal in August 2014, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. In December 2014, the Commission determined that the terms of the coal contracts were reasonable. The annual sub docket proceeding is no longer required.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a 6 year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, which began February 2014, was $42.4 million, of which $35.3 million remains as of December 31, 2014.

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; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the twelve months ended December 31, 2014 and December 31, 2013, the Company recognized Electric utility revenue of $8.7 million and $5.0 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ended electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's December 2009 Order. 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. Indiana's governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the Commission issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015.

FERC Return on Equity (ROE) Complaint
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 MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity 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. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of December 31, 2014, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $143.6 million at December 31, 2014.
This joint complaint is 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 methodology set out in its June 19, 2014 decision.
In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. As of January 2015, a settlement was not reached, and the case will move to a formal evidentiary hearing before the FERC. A procedural schedule was set on January 22, 2015, which will define a targeted date of final resolution from the FERC. An initial decision is expected later in 2015, but the timing of the final order from the FERC is unknown at this time. The Company has established a reserve pending the outcome of this complaint.

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

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.

11. Environmental Matters

Indiana Senate Bill 251
Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting SIGECO electric operations. The Company continues with its ongoing evaluation of the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality
Cross-State Air Pollution Rule
In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOX emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2 and NOX allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. After a series of legal challenges, the United States Supreme Court upheld CSAPR in April 2014, and the EPA finalized a new deadline schedule for entities that must comply, with CSAPR's first phase caps starting in 2015 and 2016, and the second phase in 2017. The Company is in full compliance with all requirements of CSAPR.

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. Reductions are to be achieved within three years of publication of the final rule in the Federal Register (April 2015). The EPA did not grant blanket compliance extensions but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Legal challenges to the MATS Rule continue. In July, a coalition of twenty-one states, including Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. On November 25, 2014, the U.S. Supreme Court agreed to hear the case, with a decision expected later in 2015.

Notice of Violation for A.B. Brown Power Plant
The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown generating station. The NOV asserts that 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. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed and approved by the IURC on January 28, 2015 in the SIGECO Electric Environmental Compliance Filing.

Information Request
SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the

information request.

Ozone NAAQS

On November 26, 2014, the U.S. 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. The EPA has stated that it intends to finalize the rule by October 2015. Upon finalization, the EPA will then determine whether a particular region is in attainment with the new standard. While it is possible that counties in southwest Indiana could be declared in non-attainment with the new standard, and thus may 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.

Water

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. To comply, the Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. The EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 however the rule is not yet finalized. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Air and Water Regulations

To comply with Indiana’s implementation plan of the Clean Air Act, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC. SCR technology is the most effective method of reducing NOX emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO’s electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO’s coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOX.

Utilization of the Company’s NOX and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

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 mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation from the EPA. The total investment is estimated to be between $80 and $90 million, roughly half of which will be made to control mercury in both air and water emissions, and the remaining investment will be made to address the issues raised in the NOV proceeding on the increase in sulfur trioxide emissions.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations.

In December 2014 the U.S. EPA released its final coal ash rule which regulates ash as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act (RCRA). At this time the final rule has not been published in the Federal Register and as such is not yet effective. Under the final rule the Company will be required to commence an enhanced groundwater monitoring program to determine whether its existing ash ponds must be closed or retrofitted with liners. The final rule allows beneficial reuse of ash and the Company will continue to beneficially reuse a majority of its ash. Legislation is currently being considered by Congress that would provide for enforcement of the federal program by states in lieu of citizen suits.

The Company originally estimated capital expenditures to comply with the alternatives in the proposal could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives was selected. As the less stringent Subtitle D program was selected by U.S. EPA in the final rule, the Company expects capital expenditures to comply in the lower end of this range. Annual compliance costs could increase only slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change
In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized two sets of GHG regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal-fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO_2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO_2 emissions by 30 percent from 2005 levels by 2030. The EPA provided an extended time frame for public commentary to December 1, 2014. The proposal sets state-specific CO_2 emission rate-based CO_2 goals (measured in lb CO_2/MWh) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO_2/MWh, and sets an interim goal of 1,607 lb CO_2/MWh and a final emission goal of 1,531 lb CO_2/MWh that must be met by 2030. Under this proposal, these CO_2 emission rate goals do not apply directly to individual units, or generating systems. They instead are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state's interim or "phase in" goal of 1,607 lb CO_2/MWh must be met as averaged over a ten-year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal, all states have unique goals based upon each state's mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana's total CO_2 emission rate compared to 2012. At 20 percent, Indiana's CO_2 emission rate reduction requirement is tied with West Virginia as the 9th lowest reduction requirement. This is due in part to the EPA's attempt to recognize the existing generating resource mix in the state and take into account each state's ability to cost effectively lower its CO_2 emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA's determination of "Best System of Emission Reductions that has been adequately demonstrated," which defines the EPA's authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state's existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO_2 emission rate. The Company timely filed comments to the Clean Power Plan proposal on December 1, 2014. The state of Indiana also filed public comments, asking that the proposal be withdrawn. Despite having just been recently proposed and not expected to be finalized until summer of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans. That litigation has been set for argument before the U.S. Court of Appeals for the D.C. circuit in April of 2015, with a decision expected later in the summer.

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:
(1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
(3) Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
(4) Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO_2 emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO_2. The Company's share of that total was 6.3 million, or less than 6 percent. Since 2005, the Company's emissions of CO_2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. 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 clean energy sources 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 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. The Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown
If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO_2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, 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. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will continue to remain engaged with the state to develop a plan for compliance and have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

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 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 to date approximately $14.3 million of the expected $15.8 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of December 31, 2014 and 2013, approximately $3.6 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

12. Fair Value Measurements

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

At December 31,

(In millions)	2014 Carrying Amount	Est. Fair Value	2013 Carrying Amount	Est. Fair Value
Long-term debt	$1,257.3	$1,408.0	$1,257.1	$1,317.4
Short-term borrowings	156.4	156.4	28.6	28.6
Cash & cash equivalents	19.3	19.3	8.6	8.6

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities recorded at fair value outstanding, and no material assets or liabilities valued using Level 3 inputs.

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 long-term debt are generally recovered in customer rates over the life of the refunding issue or over a 15-year period. Accordingly, any reacquisition would not be expected to have a material effect on the Company's results of operations.

13. Segment Reporting

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

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
Revenues			
Gas Utility Services	$944.6	$810.0	$738.1
Electric Utility Services	624.8	619.3	594.9
Other Operations	38.3	38.1	40.1
Eliminations	(38.0)	(37.8)	(39.5)
Total revenues	$1,569.7	$1,429.6	$1,333.6
Profitability Measure - Net Income			
Gas Utility Services	$57.0	$55.7	$60.0
Electric Utility Services	79.7	75.8	68.0
Other Operations	11.7	10.3	10.0
Total net income	$148.4	$141.8	$138.0
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Gas Utility Services	$93.3	$90.5	$85.4
Electric Utility Services	85.7	84.0	81.3
Other Operations	24.1	21.9	23.3
Total depreciation & amortization	$203.1	$196.4	$190.0
Interest Expense			
Gas Utility Services	$34.9	$30.6	$31.8
Electric Utility Services	29.0	29.2	33.8
Other Operations	2.7	5.2	5.9
Total interest expense	$66.6	$65.0	$71.5
Income Taxes			
Gas Utility Services	$35.7	$36.6	$39.1
Electric Utility Services	48.1	48.3	46.4
Other Operations	(0.6)	0.4	(0.2)
Total income taxes	$83.2	$85.3	$85.3
Capital Expenditures			
Gas Utility Services	$245.9	$150.5	$128.8
Electric Utility Services	92.4	100.0	108.8
Other Operations	22.8	25.8	16.2
Non-cash costs & changes in accruals	(10.1)	(13.8)	(6.2)
Total capital expenditures	$351.0	$262.5	$247.6

	At December 31,		
(In millions)	2014	2013	2012
Assets			
Gas Utility Services	$2,605.1	$2,287.9	$2,173.5
Electric Utility Services	1,659.3	1,679.0	1,705.1
Other Operations, net of eliminations	163.7	173.9	168.2
Total assets	$4,428.1	$4,140.8	$4,046.8

14. Additional Balance Sheet & Operational Information

Inventories consist of the following:

	At December 31,	
(In millions)	2014	2013
Gas in storage – at LIFO cost	$40.5	$33.2
Materials & supplies	37.2	39.0
Coal & oil for electric generation - at average cost	33.8	16.5
Other	1.7	1.2
Total inventories	$113.2	$89.9

Based on the average cost of gas purchased during December, the cost of replacing gas in storage carried at LIFO cost exceeded that carrying value at December 31, 2014 and 2013 by approximately $3 million and $9 million, respectively.

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

	At December 31,	
(In millions)	2014	2013
Prepaid gas delivery service	$40.7	$32.9
Prepaid taxes	29.5	0.2
Deferred income taxes	11.3	5.5
Other prepayments & current assets	2.0	3.8
Total prepayments & other current assets	$83.5	$42.4

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

	At December 31,	
(In millions)	2014	2013
Cash surrender value of life insurance policies	$20.8	$22.3
Municipal bond	3.2	3.4
Restricted cash & other investments	1.6	1.6
Total other investments	$25.6	$27.3

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

	At December 31,	
(In millions)	2014	2013
Refunds to customers & customer deposits	$51.3	$50.2
Accrued taxes	33.9	32.3
Accrued interest	16.1	16.2
Accrued salaries & other	21.0	28.7
Total accrued liabilities	$122.3	$127.4

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

(In millions)	2014	2013
Asset retirement obligation, January 1	$29.1	$27.3
Accretion	1.7	1.6
Changes in estimates, net of cash payments	23.8	0.2
Asset retirement obligation, December 31	$54.6	$29.1

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
AFUDC - borrowed funds	$10.8	$5.9	$4.6
AFUDC - equity funds	3.2	0.8	0.4
Nonutility plant capitalized interest	0.6	0.4	0.2
Interest income	0.7	0.6	0.6
Cash surrender value of life insurance policies	0.6	1.7	1.4
Other income	0.9	1.1	0.8
Total other – net	$16.8	$10.5	$8.0

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Cash paid (received) for:			
Interest	$66.7	$68.2	$69.6
Income taxes	63.2	30.9	30.1

As of December 31, 2014 and 2013, the Company has accruals related to utility and nonutility plant purchases totaling approximately $19.0 million and $13.1 million, respectively.

15. Subsidiary Guarantor & Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO, are guarantors of Utility Holdings' $350 million in short-term credit facilities, of which $156 million is outstanding at December 31, 2014, and Utility Holdings' $875 million unsecured senior notes outstanding at December 31, 2014. The guarantees are full and unconditional and joint and several, and Utility Holdings has no subsidiaries other than the subsidiary guarantors. However, Utility Holdings does have operations other than those of the subsidiary guarantors. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors, which are 100 percent owned, separate from the parent company's operations is required. Following are consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

Consolidating Statement of Income for the year ended December 31, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Reclassifications and Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$944.6	$—	$—	$944.6
Electric utility	624.8	—	—	624.8
Other	—	38.3	(38.0)	0.3
Total operating revenues	1,569.4	38.3	(38.0)	1,569.7
OPERATING EXPENSES				
Cost of gas sold	468.7	—	—	468.7
Cost of fuel & purchased power	201.8	—	—	201.8
Other operating	390.3	—	(35.8)	354.5
Depreciation & amortization	179.1	23.5	0.5	203.1
Taxes other than income taxes	58.4	1.7	0.1	60.2
Total operating expenses	1,298.3	25.2	(35.2)	1,288.3
OPERATING INCOME	271.1	13.1	(2.8)	281.4
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	136.7	(136.7)	—
Other – net	13.3	43.2	(39.7)	16.8
Total other income (expense)	13.3	179.9	(176.4)	16.8
Interest expense	63.9	45.2	(42.5)	66.6
INCOME BEFORE INCOME TAXES	220.5	147.8	(136.7)	231.6
Income taxes	83.8	(0.6)	—	83.2
NET INCOME	$136.7	$148.4	$(136.7)	$148.4

Consolidating Statement of Income for the year ended December 31, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Reclassifications and Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$810.0	$—	$—	$810.0
Electric utility	619.3	—	—	619.3
Other	—	37.9	(37.6)	0.3
Total operating revenues	1,429.3	37.9	(37.6)	1,429.6
OPERATING EXPENSES				
Cost of gas sold	358.1	—	—	358.1
Cost of fuel & purchased power	202.9	—	—	202.9
Other operating	369.2	—	(35.8)	333.4
Depreciation & amortization	174.6	21.3	0.5	196.4
Taxes other than income taxes	55.6	1.5	0.1	57.2
Total operating expenses	1,160.4	22.8	(35.2)	1,148.0
OPERATING INCOME	268.9	15.1	(2.4)	281.6
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	131.3	(131.3)	—
Other – net	7.1	38.5	(35.1)	10.5
Total other income (expense)	7.1	169.8	(166.4)	10.5
Interest expense	59.8	42.7	(37.5)	65.0
INCOME BEFORE INCOME TAXES	216.2	142.2	(131.3)	227.1
Income taxes	84.9	0.4	—	85.3
NET INCOME	$131.3	$141.8	$(131.3)	$141.8

Consolidating Statement of Income for the year ended December 31, 2012 (in millions):

	Subsidiary Guarantors	Parent Company	Reclassifications and Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$738.1	$—	$—	$738.1
Electric utility	594.9	—	—	594.9
Other	—	40.1	(39.5)	0.6
Total operating revenues	1,333.0	40.1	(39.5)	1,333.6
OPERATING EXPENSES				
Cost of gas sold	301.3	—	—	301.3
Cost of fuel & purchased power	192.0	—	—	192.0
Other operating	348.5	0.4	(38.8)	310.1
Depreciation & amortization	166.8	22.7	0.5	190.0
Taxes other than income taxes	51.7	1.6	0.1	53.4
Total operating expenses	1,060.3	24.7	(38.2)	1,046.8
OPERATING INCOME	272.7	15.4	(1.3)	286.8
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	127.9	(127.9)	—
Other – net	6.2	41.4	(39.6)	8.0
Total other income (expense)	6.2	169.3	(167.5)	8.0
Interest expense	65.6	46.8	(40.9)	71.5
INCOME BEFORE INCOME TAXES	213.3	137.9	(127.9)	223.3
Income taxes	85.4	(0.1)	—	85.3

NET INCOME	$127.9	$138.0	$(127.9)	$138.0

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Consolidating Balance Sheet as of December 31, 2014 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Assets				
Cash & cash equivalents	$6.9	$12.4	$—	$19.3
Accounts receivable - less reserves	113.0	—	—	113.0
Intercompany receivables	0.8	186.7	(187.5)	—
Accrued unbilled revenues	122.4	—	—	122.4
Inventories	113.2	—	—	113.2
Recoverable fuel & natural gas costs	9.8	—	—	9.8
Prepayments & other current assets	94.8	38.1	(49.4)	83.5
Total current assets	460.9	237.2	(236.9)	461.2
Utility Plant				
Original cost	5,718.7	—	—	5,718.7
Less: accumulated depreciation & amortization	2,279.7	—	—	2,279.7
Net utility plant	3,439.0	—	—	3,439.0
Investments in consolidated subsidiaries	—	1,416.9	(1,416.9)	—
Notes receivable from consolidated subsidiaries	—	746.5	(746.5)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	21.3	4.3	—	25.6
Nonutility plant - net	1.8	147.4	—	149.2
Goodwill - net	205.0	—	—	205.0
Regulatory assets	106.7	21.6	—	128.3
Other assets	29.4	1.7	(11.5)	19.6
TOTAL ASSETS	$4,264.3	$2,575.6	$(2,411.8)	$4,428.1

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Liabilities				
Accounts payable	$176.2	$4.2	$—	$180.4
Intercompany payables	15.6	0.8	(16.4)	—
Payables to other Vectren companies	28.6	—	—	28.6
Accrued liabilities	136.7	35.0	(49.4)	122.3
Short-term borrowings	—	156.4	—	156.4
Intercompany short-term borrowings	97.0	—	(97.0)	—
Current maturities of long-term debt	20.0	75.0	—	95.0
Current maturities of long-term debt due to VUHI	74.1	—	(74.1)	—
Total current liabilities	548.2	271.4	(236.9)	582.7
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	362.6	799.7	—	1,162.3
Long-term debt due to VUHI	746.5	—	(746.5)	—
Total long-term debt - net	1,109.1	799.7	(746.5)	1,162.3
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	665.8	19.3	—	685.1
Regulatory liabilities	408.8	1.5	—	410.3
Deferred credits & other liabilities	115.5	5.2	(11.5)	109.2
Total deferred credits & other liabilities	1,190.1	26.0	(11.5)	1,204.6
Common Shareholder's Equity				

Common stock (no par value)	806.9	793.7	(806.9)	793.7
Retained earnings	610.0	684.8	(610.0)	684.8
Total common shareholder's equity	1,416.9	1,478.5	(1,416.9)	1,478.5
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,264.3	$2,575.6	$(2,411.8)	$4,428.1

Consolidating Balance Sheet as of December 31, 2013 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Assets				
Cash & cash equivalents	$8.2	$0.4	$—	$8.6
Accounts receivable - less reserves	112.1	—	—	112.1
Intercompany receivables	0.3	84.8	(85.1)	—
Accrued unbilled revenues	113.5	—	—	113.5
Inventories	89.9	—	—	89.9
Recoverable fuel & natural gas costs	5.5	—	—	5.5
Prepayments & other current assets	37.3	40.1	(35.0)	42.4
Total current assets	366.8	125.3	(120.1)	372.0
Utility Plant				
Original cost	5,389.6	—	—	5,389.6
Less: accumulated depreciation & amortization	2,165.3	—	—	2,165.3
Net utility plant	3,224.3	—	—	3,224.3
Investments in consolidated subsidiaries	—	1,375.8	(1,375.8)	—
Notes receivable from consolidated subsidiaries	—	696.4	(696.4)	—
Investments in unconsolidated affiliates	0.2	—	—	0.2
Other investments	22.8	4.5	—	27.3
Nonutility plant - net	2.2	148.3	—	150.5
Goodwill - net	205.0	—	—	205.0
Regulatory assets	113.4	22.8	—	136.2
Other assets	32.2	1.0	(7.9)	25.3
TOTAL ASSETS	$3,966.9	$2,374.1	$(2,200.2)	$4,140.8

LIABILITIES & SHAREHOLDER'S EQUITY	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Liabilities				
Accounts payable	$161.6	$10.5	$—	$172.1
Intercompany payables	11.7	—	(11.7)	—
Payables to other Vectren companies	24.6	—	—	24.6
Accrued liabilities	150.3	12.1	(35.0)	127.4
Short-term borrowings	—	28.6	—	28.6
Intercompany short-term borrowings	73.1	0.3	(73.4)	—
Total current liabilities	421.3	51.5	(120.1)	352.7
Long-Term Debt				
Long-term debt - net of current maturities & debt subject to tender	382.5	874.6	—	1,257.1
Long-term debt due to VUHI	696.4	—	(696.4)	—
Total long-term debt - net	1,078.9	874.6	(696.4)	1,257.1
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	616.9	10.5	—	627.4
Regulatory liabilities	385.7	1.6	—	387.3
Deferred credits & other liabilities	88.3	3.1	(7.9)	83.5
Total deferred credits & other liabilities	1,090.9	15.2	(7.9)	1,098.2
Common Shareholder's Equity				
Common stock (no par value)	800.9	787.7	(800.9)	787.7

Retained earnings	574.9	645.1	(574.9)	645.1
Total common shareholder's equity	1,375.8	1,432.8	(1,375.8)	1,432.8
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,966.9	$2,374.1	$(2,200.2)	$4,140.8

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Consolidating Statement of Cash Flows for the year ended December 31, 2014 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	$274.4	$63.1	$—	$337.5
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Additional capital contribution from Parent	6.0	6.0	(6.0)	6.0
Long-term debt - net of issuance costs	186.6	—	(124.2)	62.4
Requirements for:				
Dividends to parent	(101.6)	(108.7)	101.6	(108.7)
Retirement of long-term debt, including premiums paid	(63.6)	—	—	(63.6)
Net change in intercompany short-term borrowings	23.9	(0.3)	(23.6)	—
Net change in short-term borrowings	—	127.8	—	127.8
Net cash flows from financing activities	51.3	24.8	(52.2)	23.9
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	101.6	(101.6)	—
Other investing activities	—	0.3	—	0.3
Requirements for:				
Capital expenditures, excluding AFUDC equity	(327.3)	(23.7)	—	(351.0)
Consolidated subsidiary investments	—	(6.0)	6.0	—
Net change in long-term intercompany notes receivable	—	(50.1)	50.1	—
Net change in short-term intercompany notes receivable	0.3	(98.0)	97.7	—
Net cash flows from investing activities	(327.0)	(75.9)	52.2	(350.7)
Net change in cash & cash equivalents	(1.3)	12.0	—	10.7
Cash & cash equivalents at beginning of period	8.2	0.4	—	8.6
Cash & cash equivalents at end of period	$6.9	$12.4	$—	$19.3

Consolidating Statement of Cash Flows for the year ended December 31, 2013 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	$371.0	$28.9	$—	$399.9
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Additional capital contribution from Parent	13.1	6.1	(13.1)	6.1
Long-term debt - net of issuance costs	232.6	273.5	(124.4)	381.7
Requirements for:				
Dividends to parent	(97.9)	(105.1)	97.9	(105.1)
Retirement of long-term debt, including premiums paid	(223.6)	(221.6)	107.7	(337.5)
Net change in intercompany short-term borrowings	(61.5)	0.3	61.2	—
Net change in short-term borrowings	—	(88.1)	—	(88.1)
Net cash flows from financing activities	(137.3)	(134.9)	129.3	(142.9)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				

Consolidated subsidiary distributions	—	97.9	(97.9)	—
Other investing activities	0.6	0.2	—	0.8
Requirements for:				
Capital expenditures, excluding AFUDC equity	(238.3)	(24.2)	—	(262.5)
Consolidated subsidiary investments	—	(13.1)	13.1	—
Net change in long-term intercompany notes receivable	—	(16.7)	16.7	—
Net change in short-term intercompany notes receivable	(0.3)	61.5	(61.2)	—
Net cash flows from investing activities	(238.0)	105.6	(129.3)	(261.7)
Net change in cash & cash equivalents	(4.3)	(0.4)	—	(4.7)
Cash & cash equivalents at beginning of period	12.5	0.8	—	13.3
Cash & cash equivalents at end of period	$8.2	$0.4	$—	$8.6

Consolidating Statement of Cash Flows for the year ended December 31, 2012 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	$335.6	$37.8	$—	$373.4
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Additional capital contribution from Parent	—	7.0	—	7.0
Long-term debt - net of issuance costs	—	99.5	—	99.5
Requirements for dividends to parent	(70.9)	(101.5)	70.9	(101.5)
Net change in intercompany short-term borrowings	(24.0)	—	24.0	—
Net change in short-term borrowings	—	(126.1)	—	(126.1)
Net cash flows from financing activities	(94.9)	(121.1)	94.9	(121.1)
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	—	70.9	(70.9)	—
Other investing activities	0.3	2.3	—	2.6
Requirements for capital expenditures, excluding AFUDC equity	(233.8)	(13.8)	—	(247.6)
Net change in short-term intercompany notes receivable	—	24.0	(24.0)	—
Net cash flows from investing activities	(233.5)	83.4	(94.9)	(245.0)
Net change in cash & cash equivalents	7.2	0.1	—	7.3
Cash & cash equivalents at beginning of period	5.3	0.7	—	6.0
Cash & cash equivalents at end of period	$12.5	$0.8	$—	$13.3

16. 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 and IFRS. 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. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company did not early adopt this guidance in accounting for the sale of its Coal Mining assets. The Company is currently evaluating the impact of this guidance, if any.

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016, and for annual and interim periods thereafter, with early application permitted. Adoption of this guidance will not have a material impact on the Company's financial statements.

17. Quarterly Financial Data (Unaudited)

Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company's utility operations. Summarized quarterly financial data for 2014 and 2013 follows:

(In millions)	Q1	Q2	Q3	Q4
2014				
Results of Operations:				
Operating revenues	$606.6	$284.5	$271.1	$407.5
Operating income	110.4	48.1	49.4	73.4
Net income	61.3	22.9	24.3	39.8
2013				
Results of Operations:				
Operating revenues	$465.5	$292.8	$267.7	$403.6
Operating income	105.4	51.2	54.5	70.5
Net income	55.1	24.2	25.3	37.2

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2014, there have been no changes to the Company’s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2014, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2014, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:
1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control over Financial Reporting

Vectren Utility Holdings, Inc.’s management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation under the framework in Internal Control — Integrated Framework (2013), the Company concluded that its internal control over financial reporting was effective as of December 31, 2014.

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

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

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

ITEM 11. EXECUTIVE COMPENSATION

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

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

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES & SERVICES

The following tabulation shows the audit and non-audit fees incurred and payable to Deloitte & Touche LLP (Deloitte) for the years ending December 31, 2014 and 2013. The fees presented below represent total Vectren Corporation (Vectren) fees, the majority of which are allocated to Utility Holdings.

	2014	2013
Audit Fees(1)	$1,506,125	$1,415,807
Audit-Related Fees(2)	585,650	530,391
Tax Fees(3)	106,575	95,589
Total Fees Paid to Deloitte(4)	$2,198,350	$2,041,787

(1) Aggregate fees incurred and payable to Deloitte for professional services rendered for the audits of Vectren's and Utility Holdings' 2014 and 2013 fiscal year annual financial statements and the review of financial statements included in their Forms 10-K or 10-Q filed during Vectren's 2014 and 2013 fiscal years. The amount includes fees related to the attestation to Vectren's assertion pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. In addition, this amount includes the reimbursement of out-of-pocket costs incurred related to the provision of these services totaling $176,925 and $128,607 in 2014 and 2013, respectively.

(2) Audit-related fees consisted principally of reviews related to various financing transactions, regulatory filings, consultation on various accounting issues, and audit fees related to the stand alone audit of certain nonutility subsidiaries consolidated by Vectren. In addition, this amount includes the reimbursement of out-of-pocket costs incurred related to the provision of these services totaling $28,250 and $12,141 in 2014 and 2013, respectively.

(3) Tax fees consisted of fees paid to Deloitte for the review of tax returns and consultation on other tax matters of Vectren and of its consolidated subsidiaries. In addition, this amount includes the reimbursement of out-of-pocket costs incurred related to the provision of these services totaling $9,755 and $11,889 in 2014 and 2013, respectively.

(4)

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

PART IV

ITEM 15. EXHIBITS & FINANCIAL STATEMENT SCHEDULES

List of Documents Filed as Part of This Report

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

Supplemental Schedules
For the years ended December 31, 2014, 2013, and 2012, the Company's Schedule II -- Valuation and Qualifying Accounts Consolidated Financial Statement Schedules is presented herein. The report of Deloitte & Touche LLP on the schedule may be found in Item 8. All other schedules are omitted as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or related notes in Item 8.

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

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at Beginning Of Year	Charged to Expenses	Charged to Other Accounts	Deductions from Reserves, Net	Balance at End of Year
(In millions)					
VALUATION AND QUALIFYING ACCOUNTS:					
Year 2014 – Accumulated provision for uncollectible accounts	$5.0	$6.1	$—	$7.2	$3.9
Year 2013 – Accumulated provision for uncollectible accounts	$5.0	$6.5	$—	$6.5	$5.0
Year 2012 – Accumulated provision for uncollectible accounts	$5.9	$7.4	$—	$8.3	$5.0
OTHER RESERVES:					
Year 2014 – Restructuring costs	$0.2	$—	$—	$0.2	$—
Year 2013 – Restructuring costs	$0.3	$—	$—	$0.1	$0.2
Year 2012 – Restructuring costs	$0.4	$—	$—	$0.1	$0.3

List of Exhibits

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

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

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

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

INDEX TO EXHIBITS

3. Articles of Incorporation and By-Laws

3.1	Articles of Incorporation of Vectren Utility Holdings, Inc. (Filed and designated in Registration Statement on Amendment 3 to Form 10, File No. 1-16739, as Exhibit 3.1)
3.2	Bylaws of Vectren Utility Holdings, Inc. as most recently amended and restated as of October 1, 2014 (Filed and designated in Current Report on Form 8-K filed September 29, 2014, File No. 1-15467, as Exhibit 3.1.)

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

4.1	Mortgage and Deed of Trust dated as of April 1, 1932 between Southern Indiana Gas and Electric Company and Bankers Trust Company, as Trustee, and Supplemental Indentures thereto dated August 31, 1936, October 1, 1937, March 22, 1939, July 1, 1948, June 1, 1949, October 1, 1949, January 1, 1951, April 1, 1954, March 1, 1957, October 1, 1965, September 1, 1966, August 1, 1968, May 1, 1970, August 1, 1971, April 1, 1972, October 1, 1973, April 1, 1975, January 15, 1977, April 1, 1978, June 4, 1981, January 20, 1983, November 1, 1983, March 1, 1984, June 1, 1984, November 1, 1984, July 1, 1985, November 1, 1985, June 1, 1986. (Filed and designated in Registration No. 2-2536 as Exhibits B-1 and B-2; in Post-effective Amendment No. 1 to Registration No. 2-62032 as Exhibit (b)(4)(ii), in Registration No. 2-88923 as Exhibit 4(b)(2), in Form 8-K, File No. 1-3553, dated June 1, 1984 as Exhibit (4), File No. 1-3553, dated March 24, 1986 as Exhibit 4-A, in Form 8-K, File No. 1-3553, dated June 3, 1986 as Exhibit (4).) July 1, 1985 and November 1, 1985 (Filed and designated in Form 10-K, for the fiscal year 1985, File No. 1-3553, as Exhibit 4-A.) November 15, 1986 and January 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1986, File No. 1-3553, as Exhibit 4-A.) December 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1987, File No. 1-3553, as Exhibit 4-A.) December 13, 1990. (Filed and designated in Form 10-K, for the fiscal year 1990, File No. 1-3553, as Exhibit 4-A.) April 1, 1993. (Filed and designated in Form 8-K, dated April 13, 1993, File No. 1-3553, as Exhibit 4.) June 1, 1993 (Filed and designated in Form 8-K, dated June 14, 1993, File No. 1-3553, as Exhibit 4.) May 1, 1993. (Filed and designated in Form 10-K, for the fiscal year 1993, File No. 1-3553, as Exhibit 4(a).) July 1, 1999. (Filed and designated in Form 10-Q, dated August 16, 1999, File No. 1-3553, as Exhibit 4(a).) March 1, 2000. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 4.1.) August 1, 2004. (Filed and designated in Form 10-K for the year ended December 31, 2004, File No. 1-15467, as Exhibit 4.1.) October 1, 2004. (Filed and designated in Form 10-K for the year ended December 31, 2004, File No. 1-15467, as Exhibit 4.2.) April 1, 2005 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.1) March 1, 2006 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.2) December 1, 2007 (Filed and designated in Form 10-K for the year ended December 31, 2007, File No 1-15467, as Exhibit 4.3) August 1, 2009 (Filed and designated in Form 10-K for the year ended December 31, 2009, File No 1-15467, as Exhibit 4.1) April 1, 2013 (Filed and designated in Form 8-K dated April 30, 2013, File No. 1-15467, as Exhibit 4.1) September 1, 2014 (filed and designated in Form 8-K dated September 25, 2014 File No. 1-15467, as Exhibit 4.1)
4.2	Indenture dated February 1, 1991, between Indiana Gas and U.S. Bank Trust National Association (formerly known as First Trust National Association, which was formerly known as Bank of America Illinois, which was formerly known as Continental Bank, National Association. Inc.'s. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494.); First Supplemental Indenture thereto dated as of February 15, 1991. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494, as Exhibit 4(b).); Second Supplemental Indenture thereto dated as of September 15, 1991, (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File

No. 1-6494, as Exhibit 4(b).); Third supplemental Indenture thereto dated as of September 15, 1991 (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File No. 1-6494, as Exhibit 4(c).); Fourth Supplemental Indenture thereto dated as of December 2, 1992, (Filed and designated in Current Report on Form 8-K filed December 8, 1992, File No. 1-6494, as Exhibit 4(b).); Fifth Supplemental Indenture thereto dated as of December 28, 2000, (Filed and designated in Current Report on Form 8-K filed December 27, 2000, File No. 1-6494, as Exhibit 4.)

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

10. Material Contracts

10.1	Vectren Corporation At Risk Compensation Plan effective May 1, 2001, (as most recently amended and restated as of May 1, 2011). (Filed and designated in Form 8-K dated May 17, 2011, File No. 1-15467, as Exhibit 10.1.)
10.2	

	Vectren Corporation Nonqualified Deferred Compensation Plan, as amended and restated effective January 1, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.32.)
10.3	Vectren Corporation Nonqualified Deferred Compensation Plan, effective January 1, 2005. (Filed and designated in Form 8-K dated September 29, 2008, File No. 1-15467, as Exhibit 10.3.)
10.4	Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees (As Amended and Restated Effective January 1, 2005).(Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.1.)

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10.5	Vectren Corporation Specimen Waiver, effective October 3, 2013, to the Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees. (Filed and designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-15467, as Exhibit 10.1.)
10.6	Vectren Corporation Nonqualified Defined Benefit Restoration Plan (As Amended and Restated Effective January 1, 2005). (Filed and designated in Form 8-K dated December 17, 2008, File No. 1-15467, as Exhibit 10.2.)
10.7	Vectren Corporation At Risk Compensation Plan stock unit award agreement for non-employee directors, effective May 1, 2009. (Filed and designated in Form 8-K, dated February 20, 2009, File No. 1-15467, as Exhibit 10.1.)
10.8	Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 31, 2013. (Filed and designated in Form 10-K, for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.2)
10.9	Vectren Corporation At Risk Compensation Plan specimen unit award agreement for officers, effective January 17, 2014. (Filed and designated in Form 10-K, for the year ended December 31, 2013, File No. 1-15467, as Exhibit 10.14)
10.10	Vectren Corporation specimen change in control agreement dated December 31, 2011. (Filed and designated in Form 8-K, dated January 5, 2012, File No. 1-15467, as Exhibit 10.1) The specimen agreement significantly differs among the named executive officers only to the extent change in control benefits are provided in the amount of three times base salary and bonus for Mr. Carl L. Chapman and two times base salary and bonus for Messer's Jerome A. Benkert, Jr., Ronald E. Christian, and William S. Doty.
10.11	Amendment Number One to the Vectren Corporation specimen change in control agreement dated December 31, 2012. (Filed and designated in Form 10-K, for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.1)
10.12	Vectren Corporation specimen severance plan agreement dated December 31, 2011. (Filed and designated in Form 8-K, dated January 5, 2012 File No. 1-15467, as Exhibit 10.2) The severance plan differs among the named executive officers only to the extent where severance benefits are provided in the amount of two times base salary for Mr. Chapman and one and one half times base salary for Messer's Benkert, Christian, and Doty.
10.13	Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.1.)
10.14	Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.2.)
10.15	Coal Supply Agreement for A.B. Brown Generating Station for 410,000 tons between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.3.)
10.16	Coal Supply Agreement for A.B. Brown Generating Station for 1 million tons between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective January 1, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated January 5, 2009, File No. 1-15467, as Exhibit 10.4.)
10.17	Amendment to F.B. Culley and A.B. Brown Coal Supply Agreements dated December 21, 2009. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 10-K, for the year ended December 31, 2009, File No. 1-15467, as Exhibit 10.1)

10.18	Amendment No. 1 to Coal Supply Agreement for Warrick 4 Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective October 31, 2011. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated November 1, 2011, File No. 1-15467, as Exhibit 10.1.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.19	Amendment No. 2 to Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective October 31, 2011. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated November 1, 2011, File No. 1-15467, as Exhibit 10.2.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.20	Amendment No. 2 to Coal Supply Agreement for A.B. Brown Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., effective October 31, 2011. Contract assigned from Vectren Fuels, Inc. to Sunrise Coal, LLC. on August 29, 2014. (Filed and designated in Form 8-K dated November 1, 2011, File No. 1-15467, as Exhibit 10.3.) Portions of the document have been omitted and filed separately pursuant to a request for confidential treatment filed with the Securities and Exchange Commission which was granted.
10.21	Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC, effective April 1, 2012. Contract assigned to ETC ProLiance Energy, LLC on June 18, 2013. (Filed and designated Form 10-K, for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.3.)
10.22	Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, effective April 1, 2012. Contract assigned to ETC ProLiance Energy, LLC on June 18, 2013. (Filed and designated Form 10-K for the year ended December 31, 2012, File No. 1-15467, as Exhibit 10.4.)
10.23	Formation Agreement among Indiana Energy, Inc., Indiana Gas Company, Inc., IGC Energy, Inc., Indiana Energy Services, Inc., Citizens Energy Group, Citizens Energy Services Corporation and ProLiance Energy, LLC, effective March 15, 1996. Contract assigned to ETC ProLiance Energy, LLC on June 18, 2013. (Filed and designated in Form 10-Q for the quarterly period ended March 31, 1996, File No. 1-9091, as Exhibit 10-C.)
10.24	Amendment Number Two to the Vectren Corporation Change in Control Agreement (specimen), dated October 1, 2014. (Filed and designated in Form 8-K, dated September 29, 2014, File No. 1-5467, as Exhibit 10.1)
10.25	Credit Agreement, dated as of October 31, 2014, among Vectren Utility Holdings, Inc., as borrower (Vectren Utility); certain subsidiaries of Vectren Utility, as guarantors; Bank of America, N.A., as administrative agent, swing line lender and a letter of credit issuer; Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein. (Filed and designated in Form 8-K, dated November 5, 2014, File No. 1-5467, as Exhibit 10.1)
10.26	Vectren Corporation At Risk Compensation Plan Stock Unit Awards Award Agreement (Officer). (Filed and designated in Form 8-K, dated December 23, 2014, File No. 1-5467, as Exhibit 10.1)
10.27	Grant Agreement for Non-Employee Director Stock Grant, dated December 31, 2014. (Filed and designated in Form 8-K, dated January 2, 2015, File No. 1-5467, as Exhibit 10.1)

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

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

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

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

99. Additional Exhibits

99.1	Amended and Restated Articles of Incorporation of Vectren Corporation effective March 31, 2000. (Filed and designated in Current Report on Form 8-K filed April 14, 2000, File No. 1-15467, as Exhibit 4.1.)
99.2	Amended and Restated Code of By-Laws of Vectren Corporation as of September 5, 2012. (Filed and designated in Current Report on Form 8-K filed October 1, 2012, File No. 1-15467, as Exhibit 3.1.)

101 Interactive Data File
101.INS XBRL Instance Document (Furnished herewith.)
101.SCH XBRL Taxonomy Extension Schema (Furnished herewith.)
101.CAL XBRL Taxonomy Extension Calculation Linkbase (Furnished herewith.)
101.DEF XBRL Taxonomy Extension Definition Linkbase (Furnished herewith.)
101.LAB XBRL Taxonomy Extension Labels Linkbase (Furnished herewith.)
101.PRE XBRL Taxonomy Extension Presentation Linkbase (Furnished herewith.)

SIGNATURES

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

VECTREN UTILITY HOLDINGS, INC.

Dated March 5, 2015 /s/ Carl L. Chapman
Carl L. Chapman
Chairman and Chief Executive Officer

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

Signature	Title	Date
/s/ Carl L. Chapman Carl L. Chapman	Chairman and Chief Executive Officer (Principal Executive Officer)	March 5, 2015
/s/ M. Susan Hardwick M. Susan Hardwick	Senior Vice President - Finance, Chief Financial Officer, and Director (Principal Accounting and Financial Officer)	March 5, 2015
/s/ Jerome A. Benkert, Jr. Jerome A. Benkert, Jr.	Executive Vice President, Chief Administrative Officer, and Director	March 5, 2015
/s/ Eric J. Schach Eric J. Schach	President and Director	March 5, 2015
/s/ Ronald E. Christian Ronald E. Christian	Executive Vice President, Chief Legal and External Affairs Officer, Secretary, and Director	March 5, 2015