VECTREN UTILITY HOLDINGS INC
Form 10-K/A
March 01, 2013

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

FORM 10-K/A
Amendment No. 1

(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, 2012
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

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, 2012, was zero. All shares outstanding of the Registrant's common stock were held by Vectren Corporation.

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

Common Stock - Without Par Value	10	February 28, 2013
Class	Number of Shares	Date

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Explanatory Note

The purpose of this Amendment No. 1 on Form 10-K/A (the "Amendment") is to correct a filing code error made when the Annual Report on Form 10-K of Vectren Corporation ("Vectren") for the year ended December 31, 2012, filed on February 15, 2013, was also inadvertently filed using the filer codes for Vectren Utility Holdings, Inc. (the "Company") as well as Vectren. This resulted in Vectren's Form 10-K incorrectly appearing as the Company's 10-K. Accordingly, this filing restates in its entirety the 10-K that was erroneously filed under the Company's filer codes on February 15, 2013. All references to Form 10-K which follow, including, without limiting the foregoing, exhibits filed pursuant to Items 601(b)(31) and 601(b)(32) of Regulation S-K, are intended to refer to the Amendment.

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

MCF / BCF: thousands / billions of cubic feet

MDth / MMDth: thousands / millions of dekatherms

MISO: Midwest 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

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
rgoocher@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.

PART I
ITEM 1. BUSINESS

Description of the Business

Vectren Utility Holdings, Inc. (the Company or Utility Holdings), 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 or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO or Vectren Ohio). 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 566,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 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 310,000 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 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, 2012, the Company had $4.0 billion in total assets, with approximately $2.2 billion (54 percent) attributed to Gas Utility Services, $1.7 billion (42 percent) attributed to Electric Utility Services, and $0.1 billion (4 percent) attributed to Other Operations. Net income for the year ended December 31, 2012, was $138.0 million, with $60.0 million attributed to Gas Utility Services, $68.0 million attributed to Electric Utility Services, and $10.0 million attributed to Other Operations. Net income for the year ended December 31, 2011, was 122.9 million. For further information regarding the activities and assets of operating segments, refer to Note 12 in the Company's consolidated financial statements included under "Item 8 Financial Statements and Supplementary Data."

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, 2012, the Company supplied natural gas service to approximately 997,400 Indiana and Ohio customers, including 911,300 residential, 84,400 commercial, and 1,700 industrial and other contract customers. Average gas utility customers served were approximately 986,100 in 2012, 983,700 in 2011, and 982,100 in 2010.

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

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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 196.0 MMDth for the year ended December 31, 2012. Gas sold and transported to residential and commercial customers was 90.2 MMDth representing 46 percent of throughput. Gas transported or sold to industrial and other contract customers was 105.8 MMDth representing 54 percent of throughput. Rates for transporting gas generally provide for the same margins earned by selling gas under applicable sales tariffs. In 2012, natural gas began being transported to a natural gas fired power plant that was recently placed into service in the Vectren South service territory. Volumes were 6.3 MMDth in 2012 and are expected to increase in 2013. Volumes delivered to the new plant are based on a monthly fixed charge.

For the year ended December 31, 2012, gas utility revenues were approximately $738.1 million, of which residential customers accounted for 68 percent and commercial 23 percent. Industrial and other contract customers account for 9 percent of revenues due to the high number of transportation customers in that customer class.

Availability of Natural Gas

The volume of gas sold is seasonal and affected by variations in weather conditions. To mitigate seasonal demand, the Company's Indiana gas utilities have storage capacity at seven 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 contract with a wholly-owned subsidiary of ProLiance Holdings, LLC (ProLiance), to ensure availability of gas. ProLiance is an unconsolidated, nonutility, energy marketing affiliate of Vectren and Citizens Energy Group (Citizens). (See the discussion of Energy Marketing below and Note 5 in the Company's Consolidated Financial Statements included in "Item 8 Financial Statements and Supplementary Data" regarding transactions with ProLiance). The Company also prepays ProLiance for natural gas delivery services during the seven months prior to the peak heating season in lieu of maintaining gas storage. Vectren received regulatory approval on March 17, 2011, from the IURC for ProLiance to continue to provide natural gas supply services to the Company's Indiana utilities and Citizens Energy Group's utilities through March 2016.

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 2012, Utility Holdings purchased 61.0 MMDth of gas at an average cost of $4.47 per Dth, of which approximately 97 percent was purchased from ProLiance and 3 percent was purchased from third party providers. The average cost of gas per Dth purchased for the previous four years was $5.30 in 2011, $5.99 in 2010, $5.97 in 2009, and $9.61 in 2008.

Electric Utility Services

At December 31, 2012, the Company supplied electric service to approximately 142,100 Indiana customers, including approximately 123,600 residential, 18,400 commercial, and 100 industrial and other customers. Average electric utility customers served were approximately 141,700 in 2012, 141,400 in 2011, and 141,300 in 2010.

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, 2012, retail electricity sales totaled 5,464.8 GWh, resulting in revenues of approximately $553.9 million. Residential customers accounted for 36 percent of 2012 revenues; commercial 27 percent; industrial 35 percent; and other 2 percent. In addition, in 2012 the Company sold 336.7 GWh through wholesale activities principally to the MISO. Wholesale revenues, including transmission-related revenue, totaled $41.0 million in 2012.

System Load

Total load for each of the years 2008 through 2012 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	7/24/2012	7/21/2011	8/4/2010	6/22/2009	7/21/2008
Total load at peak	1,259	1,220	1,275	1,143	1,167
Generating capability	1,298	1,298	1,298	1,295	1,295
Firm purchase supply	136	136	136	136	135
Interruptible contracts & direct load control	60	60	62	62	62
Total power supply capacity	1,494	1,494	1,496	1,493	1,492
Reserve margin at peak	19 %	22 %	17 %	31 %	28 %

The winter peak load for the 2011-2012 season of approximately 895 MW occurred on January 12, 2012. The prior year winter peak load for the 2010-2011 season was approximately 943 MW, occurring on December 14, 2010.

Generating Capability

Installed generating capacity as of December 31, 2012, 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 in 2009 SIGECO purchased a landfill gas electric generation project which provides 3 MW. Electric generation for 2012 was fueled by coal (97 percent), natural gas (3 percent), and landfill gas (less than 1 percent). Oil was used only for testing of gas/oil-fired peaking units. The Company generated approximately 4,998 GWh in 2012. Further information about the Company's owned generation is included in "Item 2 Properties."

There are substantial coal reserves in the southern Indiana area, and coal for coal-fired generating stations has been supplied from operators of nearby coal mines, including coal mines in Indiana owned by Vectren Fuels, Inc. (Vectren Fuels), a wholly owned subsidiary of Vectren. Approximately 2.1 million tons were purchased for generating electricity during 2012, of which approximately 80 percent was supplied by Vectren Fuels from its mines. This compares to 2.3 million tons and 2.2 million tons purchased in 2011 and 2010, respectively. The utility's coal inventory was approximately 1 million tons at December 31, 2012 and 2011.

Coal Purchases

The average cost of coal per ton purchased for the last five years was $68.65 in 2012, $75.04 in 2011, $70.47 in 2010, $64.28 in 2009, and $42.76 in 2008. Effective January 1, 2009, SIGECO began purchasing coal from Vectren Fuels under new coal

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purchase agreements. The term of these coal purchase agreements continues to December 31, 2015, with prices specified originally ranging from two to four years. The prices in these contracts were at or below market prices for Illinois Basin coal at the time of execution and were subject to a bidding process with third parties. The IURC has found that costs incurred under these contracts are reasonable. For contracts with price reopeners, amendments were finalized in 2011 for coal deliveries that began in 2012 at lower prices.

The Company received an order on January 25, 2012 to allow for the lower prices that began late in 2012 and beyond to be reflected in customer bills beginning in early 2012. Because the cost of coal expensed in 2012 was lower than amounts paid under existing contracts and included in the carrying amount of inventory at December 31, 2011, the IURC authorized deferral of the difference between costs paid under these contracts and that charged to customers for future recovery over a six year period beginning in 2014. See Rate and Regulatory Matters in Item 7 regarding coal procurement procedures and electric fuel cost reductions.

Firm Purchase Supply

The Company 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 179 GWh from OVEC in 2012.

The Company executed a capacity contract with Benton County Wind Farm, LLC in April 2008 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 2012, the Company purchased approximately 78 GWh under this contract.

In December 2009, the Company executed a 20 year power purchase agreement with Fowler Ridge II Wind Farm, LLC to purchase as much as 50 MW of energy from a wind farm located in Benton and Tippecanoe Counties in Indiana, with the approval of the IURC. The Company purchased 129 GWh under this contract in 2012.

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 Midwest and maintains operational control over the Company's electric transmission facilities as well as that of other Midwest utilities. 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 2012, in hours when purchases from the MISO were in excess of generation sold to the MISO, the net purchases were 632 GWh. During 2012, in hours when sales to the MISO were in excess of purchases from the MISO, the net sales were 322 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., Big Rivers Electric Corporation, and the City of

Jasper, Indiana, providing the ability to simultaneously interchange approximately 671 MW during peak load periods. This interchange capability varies from season to season and has been impacted in recent years as a result of ongoing initiatives to improve the transmission grid throughout the Midwest. As an example, the 345 kV Vectren transmission project that was placed into service in December 2012 will result in the ability to simultaneously interchange an additional 100 MW. 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.

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, 2012, approximately 138,000 customers in Vectren’s Ohio service territory select 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.

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, 2012, the Company and its consolidated subsidiaries had approximately 1,500 employees, of which 700 are subject to collective bargaining arrangements.

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.

In December 2011, the Company reached a three year labor agreement, ending December 1, 2014, with Local 1393 of the International Brotherhood of Electrical Workers and United Steelworkers of America Locals 12213 and 7441. This labor agreement relates to employees of Indiana Gas.

In June 2010, the Company reached a three year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 30, 2013. 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. New risks may emerge at any time, and the Company cannot predict those risks or estimate the extent to which they may affect the Company's businesses or financial performance.

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

The ability of Utility Holdings to receive dividends 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 or other payment of earnings from those entities 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 current short-term debt obligations, higher interest rates in future financings, and a smaller potential pool of investors and funding sources.

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	A3	A-
Utility Holdings commercial paper program	P-2	A-2
SIGECO's senior secured debt	A1	A

The current outlook of both Standard and Poor's and Moody's is stable and both categorize the ratings of the above securities as investment grade. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and 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 Utility Holdings’ ratings or, in each case, the ratings of its subsidiaries, it may significantly limit Utility Holdings’ access to the debt capital markets and the commercial paper market, and the Company’s borrowing costs would

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increase. In addition, Utility Holdings 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.

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 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. Currently, 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 risk related to Ohio residential gas sales.

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

Utility Holdings' businesses 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, Utility Holdings is subject to regulation by the FERC, the NERC, the EPA, the IURC, the PUCO, and the DOT. These authorities regulate many aspects of its generation, transmission and distribution operations, including construction and maintenance of facilities, operations, and safety, and its gas marketing operations involving title passage, reliability standards, and future adequacy. In addition, the IURC, PUCO, and FERC approve its utility-related debt and equity issuances, regulate the rates that Vectren's utilities can charge customers, the rate of return that Utility Holdings' utilities are authorized to earn, and its ability to timely recover gas and fuel costs. 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, waste water 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 manner. Utility Holdings' natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and improvement. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law on January 3, 2012 and the Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. While compliance costs remain uncertain, the Pipeline Safety Law is expected to result 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.

Environmental Considerations

Utility Holdings' operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with the storage, transportation, treatment, and disposal of hazardous substances and limit airborne emissions from electric generating facilities including particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation/regulation also requires that facilities, sites, and other properties associated with Utility Holdings' 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

While there have been a series of legislative proposals to address global climate change that would regulate carbon dioxide (CO_2) and other greenhouse gases and other proposals that would mandate an investment in renewable energy sources, none have been finalized to date. The US Supreme Court has determined that the EPA has the authority to regulate greenhouse gases as a pollutant under the Clean Air Act. Any future legislative or regulatory actions taken by the EPA or other agencies to address global climate change or mandate renewable energy sources could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. Further, such legislation or regulatory action would likely impact the Company's generation resource planning decisions. The Company has gathered preliminary estimates of the costs to control greenhouse gas 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 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.

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, as it relates to complying with increasing regulation and other infrastructure replacement activities are expected to be borne by the 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.

The Company's 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 cost of complying with federal mandates, 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 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 power purchase 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 Midwest and maintains operational control over SIGECO's electric transmission facilities, as well as that of other Midwest utilities. As a result of such control, SIGECO'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 transmission system, both to SIGECO'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.

Also, the MISO allocates operating costs and the cost of multi value projects throughout the region to its participating utilities such as SIGECO 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 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.

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 regulations adopted by the Commodities Futures Trading Commission (CFTC) and other agencies, the Company may be required to post additional collateral with dealer counterparties for commitments and interest rate, 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. 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 continue to evaluate the impacts as these rulemakings and interpretations become available and whether these rulemakings and interpretations affirm that exemptions apply to the Company’s use of derivative instruments.

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 state and federal 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 Vectren's retirement plans 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 regulation; and Vectren contributions. In addition, Vectren could be required to provide for significant funding of these defined benefit pension plans. Vectren relies on Utility Holdings to fund a majority of the contributions to these 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 cyber-attacks, 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, tornados, 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. Further, 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. Security breaches of this information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information. 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 attack or security breach were to occur, results of operations and financial condition could be materially adversely affected.

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 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; 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 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 natural gas marketing activities, ProLiance is a 61 percent owned energy marketing affiliate of Vectren. ProLiance relies on long-term firm transportation and storage contracts with pipeline companies to deliver natural gas to its customer base which includes the Company's Indiana utilities. Those contracts are optimized by balancing physical and financial markets and summer and winter time horizons. Therefore, recovery of these contracts' fixed costs is dependent on a number of factors, including the health of the economy, weather, changes in the availability and location of natural gas supply and related transmission assets, the price of natural gas, and the availability of credit. Optimization opportunities at current market prices or a deterioration of the customer base may result in the inability to fully recover these fixed price obligations. Recent market conditions have compressed optimization opportunities, and ProLiance has operated at a loss. If

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current market conditions continue, resulting in continued depressed asset optimization opportunities, losses could continue in future years should ProLiance be unable to adjust to the current market conditions or be unsuccessful in renegotiating its transportation and storage contracts over time. ProLiance relies on short-term borrowings and trade credit to meet its cash flow needs. ProLiance has borrowing capacity through a syndicated credit facility. The current facility expires in May 2014. Should ProLiance be unsuccessful in maintaining short-term borrowing capacity and trade credit in the future, ProLiance's results of operations and financial condition could be adversely impacted.

Related to Vectren's nonutility infrastructure services activities, Miller Pipeline, LLC and Minnesota Limited, Inc. are wholly owned by Vectren and provide underground pipeline construction and repair to Utility Holdings' utility infrastructure. Risks specific to Vectren's infrastructure services 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 multi-employer 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 coal mining activities, Vectren Fuels is wholly owned by Vectren and is supplier of coal to Utility Holdings’ Indiana electric utility. Risks specific to Vectren’s coal mining strategies include, but are not limited to, failure to fully access coal at owned mines; failure for the contract operator to operate owned mines in accordance with MSHA guidelines and regulations, recent interpretations of those guidelines and regulations, and any new guidelines or regulations that could be implemented and to respond to more frequent and broader inspections; failure to negotiate and execute new sales contracts; failure to adapt to any new laws or rules, such as climate change or air quality legislation, that impact users of coal; failure to manage coal mining production and production costs and other risks in response to changes in demand; changes in market demand for Vectren Fuels' coal including impacts of fuel switching to alternative sources and coal specifications in terms of sulfur and mercury, among others; geologic, equipment, and operations risks; supplier and contract miner performance; the availability of miners, key equipment and commodities; availability of transportation; the ability to access/replace coal reserves; significant variations in weather that could impact coal sales and production; and unanticipated changes in coal commodity prices.

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 properly estimate the cost to construct projects; failure to develop or obtain gas storage field and mining property; potential legislation that may limit CO_2 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.

Credit ratings of individual entities within a consolidated organization can be influenced by changes in business prospects and developments of other entities within that organization. Thus, material adverse developments affecting those other entities related to Vectren could result in a downgrade in Utility Holdings’ credit ratings or outlook, limit its ability to access the debt markets, bank financing and commercial paper markets and, thus, its liquidity.

Vectren’s nonutility businesses support Utility Holdings’ utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services. 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 143,500 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 with ProLiance for 12.5 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 245,867 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 6.3 BCF of gas with maximum peak day delivery capabilities of 108,500 MCF per day. In addition to its company owned storage delivery capabilities, SIGECO has contracted with ProLiance for 0.4 BCF of interstate pipeline storage service with a maximum peak day delivery capability of 16,812 MMBTU per day. SIGECO's gas delivery system includes 3,200 miles of distribution and transmission mains, all of which are located in Indiana.

During 2012, VEDO retired three propane plants, all of which were located in Ohio. The plants were capable of storing 0.5 million gallons of propane, and the plants could manufacture for delivery 52,200 MCF of manufactured gas per day. VEDO has contracted for 11.8 BCF of natural gas delivery service with a maximum peak day delivery capability of 246,080 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, 2012, 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 Culley 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. In 2009, SIGECO, with IURC approval, purchased a landfill gas electric generation project in Pike County, Indiana with a total capability of 3 MW.

SIGECO's transmission system consists of 1,014 circuit miles of 345Kv, 138Kv and 69Kv lines. The transmission system also includes 37 substations with an installed capacity of 4,863 megavolt amperes (Mva). The electric distribution system includes 4,301 pole miles of lower voltage overhead lines and 381 trench miles of conduit containing 2,098 miles of underground distribution cable. The distribution system also includes 96 distribution substations with an installed capacity of 2,990 Mva and 54,000 distribution transformers with an installed capacity of

2,363 Mva.

SIGECO owns utility property outside of Indiana approximating 24 miles of 138Kv and 345Kv electric transmission lines, which are included in the 1,014 circuit miles discussed above, located in Kentucky and which interconnects 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."

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

During 2012, Utility Holdings paid dividends of $25.0 million to its parent company in the first quarter and $25.5 million in each of the second through fourth quarters.

During 2011, Utility Holdings paid dividends of $22.9 million to its parent company in each of the quarters.

In the first quarter of 2013, Utility Holdings paid a $26.3 million dividend to its parent company.

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)	2012	2011	2010	2009	2008
Operating Data:					
Operating revenues	$1,333.6	$1,457.0	$1,563.7	$1,596.2	$1,958.7
Operating income	286.8	281.8	277.0	238.0	254.6
Net income	138.0	122.9	123.9	107.4	111.1
Balance Sheet Data:					
Total assets	$4,046.8	$3,974.5	$3,924.5	$3,823.1	$3,838.1
Long-term debt - net of current maturities & debt subject to tender	1,103.4	1,208.2	1,024.8	1,254.8	1,065.1
Common shareholder's equity	1,390.0	1,346.6	1,315.4	1,274.7	1,242.9

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.

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 2012, Utility Holdings earned $138.0 million, compared to $122.9 million in 2011 and $123.9 million in 2010. Results over the last three years reflect, among other things, the impacts of new electric base rates implemented on May 3, 2011, lower interest expense as a result of refinancing activity completed late in 2011 and early 2012, and the impact of recent regulatory orders in the Ohio natural gas service territory allowing for recovery of and accounting for infrastructure replacement activities. Operating expenses increased in 2011 compared to 2010 due to expected increases in planned maintenance. Operating expenses in 2012 were generally flat as compared to 2011. Results in 2011 also include unfavorable income tax adjustments primarily resulting from the sale of Vectren Source, a former wholly owned subsidiary of Vectren.

Gas utility services

The gas utility segment earned $60.0 million during the year ended December 31, 2012, compared to earnings of $52.5 million in 2011 and $53.7 million in 2010. The increased earnings in 2012 reflect revenues and the deferral for future recovery of some operating expenses from regulatory orders allowing for recovery of and accounting for infrastructure replacement activities in Ohio. Year-over-year, interest expense was also favorably impacted by financing transactions completed in late 2011 and early 2012. In 2011, increased operating expenses associated with planned maintenance activities, environmental remediation efforts, and a brief work stoppage related to bargaining unit labor negotiations unfavorably impacted earnings compared to 2010.

Electric utility services

The electric operations earned $68.0 million during 2012, compared to $65.0 million in 2011 and $60.9 million in 2010. Results in 2012 and 2011 were positively impacted by new electric base rates implemented on May 3, 2011. In addition, lower interest costs associated with refinancing activity favorably impacted results in 2012. These increased results in 2012 were somewhat offset by lower small customer margin from conservation initiatives net of lost margin recovery. The increased earnings in 2011 driven by the base rate increase, compared to 2010, were offset somewhat by summer weather that, while warmer than normal, was cooler than the extreme summer temperatures in 2010. Earnings in 2011 were also reduced by increased power supply operating expenses associated with planned electric generating maintenance activities.

Other utility operations

In 2012, earnings from other utility operations were $10.0 million, compared to $5.4 million in 2011 and $9.3 million in 2010. Differences in the Utility Group's effective tax rate among the periods presented resulted in the lower earnings in 2011. The higher income tax rate in 2011 was driven by the revaluation of Utility Group deferred income taxes related to the fourth quarter 2011 sale of Vectren Source, a nonutility retail energy marketer, which resulted in a charge to Utility Group income taxes of approximately $2.8 million. 2011 also includes a $1.4 million unfavorable tax adjustment.

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.

Over the last six years, orders establishing new base rates have been received by each utility. SIGECO's electric territory received an order in April 2011, effective May 2011, and its gas territory received an order in August 2007. Indiana Gas received its most recent base rate order in February 2008 and VEDO 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 innovative rate design strategies that have been authorized by these state commissions. Outside of a full base rate proceeding, these approaches mitigate to some extent the impacts of investments in government-mandated and other infrastructure replacement projects, operating costs that are volatile, and changing consumption patterns. In addition to timely gas and fuel cost recovery, approximately $36 million of the Utility Group's approximate $310 million in Other operating expenses incurred during 2012 are subject to recovery mechanisms outside of base rates.

Rate Design Strategies

Sales of natural gas and electricity to residential and commercial customers are largely seasonal and are impacted by weather. Trends in average use 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 (NTA) and decoupling mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns. The Ohio natural gas service territory has a straight fixed variable rate design for its residential customers. This rate design, which was fully implemented in February 2010, mitigates approximately 90 percent of the Ohio service territory's weather risk and risk of decreasing consumption. Prior to the implementation of this rate design, the Ohio service territory had a decoupling mechanism. In all natural gas service territories, commissions have authorized bare steel and cast iron replacement programs. 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 (GCA) 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, subject to caps that are based on historical experience. Electric rates contain a fuel adjustment clause (FAC) that allows for timely adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to an approved variable benchmark based on NYMEX natural gas prices, is also timely recovered through the FAC.

GCA and FAC procedures involve periodic filings and IURC hearings to establish the amount of 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

FAC earnings test had some impact on the Company’s 2012 operating results, as discussed below.

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 standard base rate recovery. Certain operating costs, including depreciation, associated with regional electric transmission assets not in base rates are also recovered by mechanisms outside of standard base rate recovery. In Ohio, expenses such as

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uncollectible accounts expense, costs associated with exiting the merchant function, and costs associated with a distribution riser replacement program are subject to recovery outside of base rates. Revenues and margins are also impacted by the collection of state mandated taxes, which primarily fluctuate with gas and fuel costs.

In 2011, state laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects, and in Ohio other capital investment projects, outside of a base rate proceeding. Utilization of these mechanisms will likely increase in the coming years.

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 earnings 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. 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)	2012	2011	2010
Gas utility revenues	$738.1	$819.1	$954.1
Cost of gas sold	301.3	375.4	504.7
Total gas utility margin	$436.8	$443.7	$449.4
Margin attributed to:			
Residential & commercial customers	$369.5	$375.2	$384.7
Industrial customers	56.7	56.4	52.2
Other	10.6	12.1	12.5
Sold & transported volumes in MMDth attributed to:			
Residential & commercial customers	90.2	99.9	106.2
Industrial customers	105.8	97.0	90.8
Total sold & transported volumes	196.0	196.9	197.0

Gas utility margins were $436.8 million for year ended December 31, 2012, and compared to 2011, decreased $6.9 million. The impact of low natural gas prices and mild weather on revenue taxes, late and reconnect fees, and volumetric pass through costs decreased gas utility margin $10.9 million in 2012 compared to 2011. Returns generated on investments in infrastructure replacement in Ohio increased margins $2.9 million in 2012 compared to the prior year. Excluding the impact of regulatory initiatives and pass through costs, large customer margins increased $1.0 million on increasing volumes. With rate designs that substantially limit the impact of weather on margin, heating temperatures in 2012 that were 79 percent of normal in Indiana and 88 percent of normal in Ohio had a significant impact on small volumes sold, but only a slightly negative impact on margin, reducing margin $0.6 million year over year. Large customer volumes in 2012 compared to 2011 significantly increased due to natural gas transported to a natural gas fired power plant that was recently placed into service in the Vectren South service territory. Volumes delivered to this customer are based on a monthly fixed charge and began in 2010 when service was initiated.

For the year ended December 31, 2011, gas utility margins decreased $5.7 million compared to 2010. Margin decreased $8.0 million year over year due to lower revenue taxes and operating costs recovered in margin. Management estimates a decrease of $3.5 million due to Ohio rate design changes, as described below. Returns generated on investments in infrastructure replacement in Ohio increased margins $2.2 million year over year. Large customer margin, net of the impacts of regulatory initiatives and pass through costs, increased by $3.8 million due primarily to ethanol producers.

The rate design approved by the PUCO on January 7, 2009, and initially implemented on February 22, 2009, allowed for the phased movement toward a straight fixed variable rate design. This rate design places substantially all of the fixed cost recovery in the monthly customer service charge. Since the straight fixed variable rate design was fully implemented for residential base rates in February 2010, nearly 90 percent of the combined residential and commercial base rate gas margins were recovered through the customer service charge since that date. Margin recognized in 2011 reflects the full implementation of the rate design which resulted in a decrease in margin in 2011 compared to 2010. In 2010, there was volumetric recovery during the peak delivery periods of January and February.

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)	2012	2011	2010
Electric utility revenues	$594.9	$635.9	$608.0
Cost of fuel & purchased power	192.0	240.4	235.0
Total electric utility margin	$402.9	$395.5	$373.0
Margin attributed to:			
Residential & commercial customers	$258.5	$255.8	$241.2
Industrial customers	103.4	101.6	97.1
Municipals & other customers	8.9	8.5	8.5
Subtotal: Retail	$370.8	$365.9	$346.8
Wholesale margin	32.1	29.6	26.2
Total electric utility margin	$402.9	$395.5	$373.0
Electric volumes sold in GWh attributed to:			
Residential & commercial customers	2,731.7	2,827.2	2,964.0
Industrial customers	2,710.5	2,744.8	2,630.3
Municipals & other	22.6	22.8	22.6
Total retail & firm wholesale volumes sold	5,464.8	5,594.8	5,616.9

Retail
Electric retail utility margins were $370.8 million for the year ended December 31, 2012 and, compared to 2011, increased by $4.9 million. The impact year over year of new retail base rates that were effective May 3, 2011 was an increase in margin of approximately $10.0 million. Offsetting a portion of the increase was a decline in small customer usage that lowered margin by $2.6 million in 2012 as a result of energy conservation, net of an approved lost margin recovery mechanism. Weather also impacted margin and, compared to normal temperatures, increased results $2.7 million and $3.0 million, in 2012 and 2011, respectively. Due in part to the favorable weather in both periods, the Company provided refunds to customers in 2012 totaling $2.6 million pursuant to the statutory earnings test. Indiana regulation includes a statutory mechanism that can limit a utility's rolling twelve month net operating income to that authorized in its last general rate order, as adjusted for previous net operating income levels that were below authorized levels. Should weather or other factors continue to increase net operating income in future periods, the full benefit of those favorable impacts on the Company's electric utility may continue to be limited by the statutory earnings test. Finally, though volumes sold to large customers during 2012 decreased, the impact on margin was small as certain large customers have rate structures that include both a daily peak usage component, as well as a volumetric component.

In 2011, electric retail utility margins increased $19.1 million compared to 2010. The impact of new base rates increased margin $23.7 million. Management estimates the impact of weather, which was warmer than normal but cooler compared to the prior year, to have decreased residential and commercial margin $7.4 million. Margin increased $2.4 million year over year due to increased MISO operating costs that are recovered in margin. In 2010, management estimates that cooling weather 134 percent of normal increased margin compared to normal by $10.4 million.

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)	2012	2011	2010
Transmission system margin	$26.4	$23.5	$18.8
Off-system margin	5.7	6.1	7.4
Total wholesale margin	$32.1	$29.6	$26.2

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $26.4 million during 2012, compared to $23.5 million in 2011 and $18.8 million in 2010. Increases are primarily due to increased investment in qualifying projects. To date, the Company has invested $155 million in qualifying projects. These projects include an interstate 345 Kv transmission line that connects Vectren'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. Once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance, and operating expenses are also recovered. The 345 Kv project is the largest of these qualifying projects, with a cost of $107 million that earned the FERC approved equity rate of return while under construction. The last segment of that project was placed into service in December 2012.

For the year ended December 31, 2012, margin from off-system sales was $5.7 million, compared to $6.1 million in 2011 and $7.4 million in 2010. 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 be shared equally with customers. This compares to a $10.5 million sharing threshold established in 2007. Results for the periods presented reflect the impact of that sharing. Off-system sales totaled 336.7 GWh in 2012, compared to 586.7 GWh in 2011, and 587.6 GWh in 2010. The lower volumes sold in 2012 from Vectren South's primarily coal-fired generation result from increased sales of power in MISO from gas-fired electric generation due to low natural gas prices and more wind generation.

Operating Expenses

Other Operating

For the year ended December 31, 2012, Other operating expenses were $310.1 million, and compared to 2011, decreased $3.0 million. Excluding pass through costs, expenses were essentially flat. Continuous improvement initiatives throughout the Utility Group are being implemented to limit growth in operating expenses over the coming years. The Company estimates that in 2012 these initiatives have resulted in sustainable savings of more than $7 million. Examples of the initiatives implemented in 2012 include improved processes that have allowed the Company to become more efficient in completing work and thereby reduce labor costs and recent amendments to postretirement medical plans that provide better access to benefits for retirees at lower costs to the Company. These sustainable savings have aided in offsetting planned increases in energy delivery related operating expenses.

For the year ended December 31, 2011, Other operating expenses increased $13.9 million compared to 2010. The increase is primarily attributable to higher electric power supply operating expenses. Such expenses increased $10.8 million year over year with $6.9 million attributed to planned outage maintenance and $3.1 million attributed to variable production costs. The remaining variance is primarily attributable to higher expected energy delivery costs.

Depreciation & Amortization

For the year ended December 31, 2012, depreciation and amortization expense was $190.0 million, compared to $192.3 million in 2011 and $188.2 million in 2010. The periods presented reflect increased utility plant investments placed into service.

However, in 2012 regulatory orders allowing for deferral of depreciation on capital investments previously placed into service were received that more than offset the impact of utility plant increases in 2012 and partially offset increases in 2011.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $0.6 million in 2012 compared to 2011 and decreased $5.6 million in 2011 compared to 2010. The decrease in 2012 was primarily due to lower usage taxes associated with lower gas and fuel costs. The decrease in 2011 is primarily attributable to lower Ohio excise and usage taxes associated with that territory's process of exiting the merchant function. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with lower gas utility revenues.

Other Income-Net

Other income-net reflects income of $8.0 million in 2012, compared to $4.3 million in 2011 and $5.4 million in 2010. Results in 2012 include approximately $2.2 million of increased AFUDC compared to 2011. AFUDC in 2012 reflects the impact of recent regulatory orders related to the infrastructure replacement investments. In addition, results in 2012 and in 2010 reflect increased returns on assets that fund benefit plans compared to 2011.

Interest Expense

For year ended December 31, 2012, interest expense was $71.5 million, compared to $80.3 million in 2011 and $81.4 million in 2010. The decreases among the years are primarily due to fourth quarter 2011 refinancing activity in which $250 million of long-term debt with a 6.625 percent interest rate matured and was replaced with $150 million of new long-term debt with an average interest rate of 5.12 percent and $100 million of short-term borrowings. During the fourth quarter of 2011, the Company also called $96.2 million of long-term debt at a rate of 5.95 percent and replaced that issuance in February 2012 with new debt at a rate of 5.0 percent.

Income Taxes

In 2012, Utility Group federal and state income taxes were $85.3 million, compared to $82.9 million in 2011 and $77.1 million in 2010. Changes in income taxes are primarily driven by changes in pre-tax income. In addition, the effective income tax rate in 2011 was higher primarily due to the revaluation of Utility Group deferred income taxes from the fourth quarter sale of Vectren Source which resulted in a $2.8 million charge, and a $1.4 million unfavorable tax adjustment recognized earlier in that year.

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 replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and operational improvement. In 2011, laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects, and in Ohio other capital investment projects, outside of a base rate proceeding. Utilization of these recovery mechanisms is discussed below.

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 upon 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 recovered through the DRR. To date, the Company has made capital investments under this rider totaling $80 million. During 2012, 2011, and 2010 gas operating revenues associated with the DRR were $6.5 million, $3.6 million, and $1.4 million, respectively. Other Income associated with the debt-related post in service carrying costs totaled $1.8 million, $2.0 million, and $0.9 million for 2012, 2011, and 2010, respectively. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $6.5 million, $3.0 million, and $1.0 million at December 31, 2012, 2011, and 2010, respectively.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. Once such application is approved, the legislation authorizes a deferral of costs, such as depreciation, property taxes, and debt-related carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law. The order provides for the deferral of depreciation, debt-related post in service carrying costs, and property taxes for its $23.5 million capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. The order created a regulatory asset as of December 31, 2012 of $1.5 million, of which $0.9 million is Other Income related to the accrual of post in service carrying costs, and the remaining $0.6 million is the deferral of depreciation and property tax expense. The Company expects to make a future request for similar accounting authority on its capital expenditure program for the calendar year 2013.

Based on the deferral of costs and continuing recognition of debt-related post in service carrying costs using the 2009 capital structure, Regulatory assets associated with these infrastructure programs increased $5.0 million in 2012. Regulatory assets are expected to continue to increase in future periods as post in service carrying costs are recognized in the statement of income and operating costs are deferred. Historical relationships between rate base growth and depreciation expense and property taxes will also be impacted.

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 Vectren North and $3 million annually at Vectren South. For USGAAP accounting purposes only the debt-related post in service carrying costs are recognized in the Consolidated Statements of Income currently. Such deferral is limited by individual qualifying project to three years after being placed into service at Vectren South and four years after being placed into service at Vectren North. The debt-related post in service rate used to calculate the deferral is based on a current cost of funds. At December 31, 2012 and 2011, the Company has USGAAP regulatory assets totaling $8.5 million and $4.7 million, respectively, associated with the deferral of depreciation and debt-related post in service carrying cost activities.

In April 2011, 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 are to be deferred for future recovery in the utility's next general rate case. To date, the Company has not initiated a filing requesting authority to recover costs using the Senate Bill 251 approach and continues to study its applicability to expenditures associated with its natural gas distribution operations.

Pipeline Safety Law

On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years Those regulations may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the law is expected to result 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. Operating expenses associated with expanded compliance requirements may grow by approximately $9 million annually, with $6 million attributable to the Indiana operations. Related to the Indiana operations, the Company expects to seek recovery under Senate Bill 251, or such costs may be recoverable through current tracking mechanisms. Capital investments, associated with the Pipeline Safety Law, are expected to be significant. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 or other currently authorized recovery mechanisms, such as the Distribution Replacement Rider, in Ohio.

Vectren South Electric Base Rate Filing

On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. The IURC issued an order in the case on April 27, 2011. The order provided for a revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent, and an overall rate of return of 7.29 percent. The new rates were effective May 3, 2011. The IURC, in its order, provided for deferred accounting treatment related to the Company's estimated $32 million investment in dense pack technology, of which approximately $25.5 million has been invested as of December 31, 2012. In addition, the IURC denied the Company’s request for implementation of the decoupled rate design, which is discussed further below. Addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions would be initiated.

Coal Procurement Procedures

Vectren South submitted a request for proposal (RFP) in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the electric rate case, a sub docket proceeding was established to review the Company’s prospective coal procurement procedures, and the Company submitted evidence related to its 2011 RFP. In March 2012, the IURC issued its order in the sub docket which concluded that Vectren South’s 2011 RFP process resulted in the lowest fuel cost reasonably possible. In late 2012, Vectren South terminated its contract with one of the suppliers due to coal quality issues that were identified during test burns of the coal. In addition to coal purchased under these contracts, Vectren South has also contracted with Vectren Fuels, Inc. to purchase lower priced spot coal. This spot purchase was found to be reasonable in a recent FAC order. The IURC will continue to regularly monitor Vectren South’s procurement process in future fuel adjustment proceedings.

Delivery to Vectren's power plants of lower-priced contract coal from the April 2011 RFP process began during 2012. On December 5, 2011 within the quarterly FAC filing, Vectren South 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 these new term contracts effective after 2012. The cost difference will be deferred to a regulatory asset and 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. The deferred amount includes a reduction in the value of the coal inventory at December 31, 2011 of approximately $17.7 million to reflect existing coal inventory at the new, lower price. Deferrals related to coal purchases in 2012 have totaled approximately $24.7 million, bringing the total deferred balance as of December 31, 2012, to the expected level of $42.4 million.

Vectren South Electric Demand Side Management Program Filing

On August 16, 2010, Vectren South filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South 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 discussed earlier.

Vectren North Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. The Company seeks further clarity on the scope of the requirement and the ability to also use contractors to perform certain inspections. A schedule for the rehearing proceeding will be set in March 2013.

Vectren North & Vectren South Gas Decoupling Extension Filing

On April 14, 2011, the Company’s Indiana based gas companies (Vectren North and Vectren South) filed with the IURC a joint settlement agreement with the OUCC on an extension of the offering of conservation programs and the supporting gas decoupling mechanism originally approved in December 2006. On August 18, 2011, the IURC issued an order approving the settlement as filed, granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015.

VEDO Gas Rate Design

The rate design approved by the PUCO on January 7, 2009, and initially implemented on February 22, 2009, allowed for the phased movement toward a straight fixed variable rate design, which places substantially all of the fixed cost recovery in the monthly customer service charge. This rate design mitigates most weather risk as well as the effects of declining usage, similar to the company’s lost margin recovery mechanism in place in the Indiana natural gas service territories and the mechanism in place in Ohio prior to this rate order. Since the straight fixed variable rate design was fully implemented for residential base rates in February 2010, nearly 90 percent of the combined residential and commercial base rate gas margins were recovered through the customer service charge. As a result, some margin previously recovered during the peak delivery winter months, such as January and the first half of February 2010, is more ratably recognized throughout the year.

VEDO Continues the Process to Exit the Merchant Function

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

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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.

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 (SO_2), 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 Vectren South's electric operations. The Company is currently evaluating the impact Senate Bill 251 may have on its operations, including applicability to 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 (Formerly Clean Air Interstate Rule (CAIR))
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 SO_2 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 SO_2 and NOx allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSAPR set individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances to generating units through state implementation plans, CSAPR allowances were allocated to individual units directly through the federal rule. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. Multiple administrative and judicial challenges were filed. On December 30, 2011, the Court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the Court vacated CSAPR and directed the EPA to continue to administer CAIR. In October 2012, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. EPA's request for rehearing was denied by the Court on January 24, 2013. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air Regulations").

Mercury and Air Toxics (MATS) Rule
On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule is the EPA’s response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

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

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hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR's implementation by the Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA also recently announced it will reconsider MATS requirements for new construction. Such requirements
are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology.

Conclusions Regarding Air Regulations
To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, 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 Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). 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 new 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 SO_2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO_2 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.

The Company is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule and the 2015 requirement imposed by CAIR. Based upon an initial review, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment. However, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required and could be significant depending on the required method of compliance with the requirements. While the Company has not yet quantified what the additional costs may be associated with these efforts, because the compliance is required by government regulation the Company believes that such additional costs, if incurred, should be recoverable under Indiana Senate Bill 251 referenced above.

Notice of Violation Received
The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements. At this time the Company is reviewing the potential impact this NOV could have on capital expenditures and operating costs. To the extent costs to comply increase, they should be recoverable under Indiana law.

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in 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. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized, the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2013. Depending on the final rule and on the Company's facts and circumstances, capital investments could approximate $40 million if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. 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. EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. EPA is under an April 19, 2013 deadline to complete its rule proposal. 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 recovered under Senate Bill 251 referenced above.

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 by-products 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. Rules have not been finalized given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company's ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as$30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase 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 recovered under Senate Bill 251 referenced above.

Climate Change

The Company 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 coal 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 to reduce dependence on foreign oil.

The Company emits greenhouse gases (GHG) primarily from its fossil fuel electric generation plants. The Company uses the methodology described in the Acid Rain Program (under Title IV of the Clean Air Act) to calculate its level of direct CO_2 emissions from its fossil fuel electric generating plants. The Company's direct CO_2 emissions from its plants over the past 5 years are represented below:

(in thousands)	2012	2011	2010	2009	2008
Direct CO_2 Emissions (tons)	6,083	5,645	6,120	5,500	8,029

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company's direct CO_2 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;
- Building a renewable energy portfolio to complement base load coal-fired generation in advance of mandated renewable energy portfolio standards;
- 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;
- 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.

Legislative Actions & Other Climate Change Initiatives

In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas 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 greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. EPA's PSD and Title V permitting rules for GHG's were recently upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards for greenhouse gases for new electric generating facilities under Clean Air Act Section 111(b). While standards for new sources are not yet final, EPA has signaled its intent to propose New Source Performance Standards for greenhouse gases for existing electric generating units under Section 111(d), which would be applicable to the Company's existing units. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown

If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other greenhouse gases 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 greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas 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 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. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. The financial incentives include an enhanced return on equity and tracking mechanisms to recover program costs. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2009, the Company also executed a long term purchase power commitment for 50 MW of wind energy. These transactions supplement a 30 MW wind energy purchase power agreement executed in 2008. Before the impacts of efficiency measures which are defined as clean energy in the legislation, the Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. The Company continues to evaluate whether to participate in this voluntary program.

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 $41.7 million ($23.2 million at Indiana Gas and $18.5 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 million of the expected $15 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, 2012 and 2011, approximately $4.6 million and $6.5 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to both the Indiana Gas and SIGECO sites.

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Impact of Recently Issued Accounting Guidance

Other Comprehensive Income (OCI)

In 2011, the FASB issued new accounting guidance regarding the presentation of comprehensive income within financial statements. The new guidance requires entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. Under the two-statement approach, the first statement would include components of net income, which is consistent with the income statement format used today, and the second statement would include components of OCI. The guidance does not change the items that must be reported in OCI. The new guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and retrospective application is required. The Company adopted this guidance for the quarterly reporting period ending March 31, 2012; however, other comprehensive income, including its individual components, was not material to the financial statements taken as a whole and thus a statement of comprehensive income is not provided.

Goodwill Testing

In September 2011, the FASB issued new accounting guidance regarding testing goodwill for impairment. The new guidance allows the Company an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Using the new guidance, the Company no longer would be required to calculate the fair value of a reporting unit unless the Company determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Company considered this option during its quarterly reporting period ended March 31, 2012 and concluded the continuation of the use of a quantitative approach is appropriate.

Fair Value Measurement and Disclosure

In May 2011, the FASB issued accounting guidance to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and International Financial Reporting Standards (IFRS). The amendments are not intended to change the application of the current fair value requirements, but to clarify the application of existing requirements. The guidance does change particular principles or requirements for measuring fair value or disclosing information about fair value measurements. To improve consistency, language has been changed to ensure that U.S. GAAP and IFRS fair value measurement and disclosure requirements are described in the same way. The Company adopted this guidance for its quarterly reporting period ended March 31, 2012. The adoption of this guidance did not have a material impact on the Company's financial position, results of operations or cash flows.

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, all 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 as identified in Note 12 to the consolidated financial statements 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 2012 periodic benefit cost: a discount rate of approximately 4.8 percent, an expected return on plan assets of 7.75 percent, a rate of compensation increase of 3.5 percent, and an inflation assumption of 2.75 percent. Due to low interest rates, the discount rate is 70 basis points lower from the assumption used in 2011. The rate of return and inflation rates were also lowered by 25 basis points. To estimate 2013 costs, the discount rate, expected return on plan assets, rate of compensation increase, and inflation assumption were approximately 4.0 percent, 7.75 percent, 3.5 percent, and 2.75 percent respectively, reflecting the further reductions in interest rates. Vectren's management currently estimates a pension and postretirement cost of approximately $13 million in 2013, compared to approximately $12 million in 2012, $13 million in 2011, and $14 million in 2010. 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 estimates that a 50 basis point decrease in the discount rate used to estimate retirement costs generally increases periodic benefit cost by approximately $1.5 million to $2.0 million. However, the impact of increases associated with a lower discount rate are partially offset by the impact of plan contributions and a plan amendment related to the postretirement medical plan.

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 Indiana Gas, SIGECO, 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, including current maturities, and short-term obligations outstanding at December 31, 2012 approximated $821 million and $117 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, 2012 was $387 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, 2012, are A-/A3 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/A1. Utility Holdings' commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-60 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 53 percent of long-term capitalization at both December 31, 2012 and 2011, 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, 2012, the Company was in compliance with all debt covenants.

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Available Liquidity in Current Credit Conditions

The Company’s A-/A3 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, which have been enhanced by bonus depreciation legislation, and refinancing maturing debt using the capital markets. 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 timing and amount of such investments depends on a variety of factors, including available liquidity. Specifically for 2013, the Company plans to access the capital markets to refinance debt maturities or debt that is callable. The Company currently has firm commitments for a debt issuance totaling $125 million which is more fully described below.

Long-term debt transactions completed in 2012 and 2011 include issuances by Utility Holdings totaling $250 million. No long-term debt transactions were completed in 2010. These transactions are more fully described below. (See Financing Cash Flow).

Consolidated Short-Term Borrowing Arrangements
At December 31, 2012, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2012, approximately $233 million was available. This short-term credit facility was renewed in November 2011 and is available through September 2016. 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)	2012		2011		2010	
Year End						
Balance Outstanding	$116.7		$242.8		$47.0	
Weighted Average Interest Rate	0.40	%	0.57	%	0.41	%
Annual Average						
Balance Outstanding	$77.6		$39.6		$14.0	
Weighted Average Interest Rate	0.47	%	0.48	%	0.40	%
Maximum Month End Balance Outstanding	$214.2		$242.8		$47.0	

Throughout 2012, 2011, and 2010, 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, stock option plan, and other employee benefit plan requirements and contribute those proceeds to Utility Holdings. New issuances in 2012 and 2010 contributed to Utility Holdings added additional liquidity of $7.0 million and $4.7 million, respectively. There were no new issuances contributed to Utility Holdings in 2011.

Potential Uses of Liquidity

Planned Capital Expenditures
During 2012, capital expenditures and other investments approximated $250 million, compared to $230 million in each of 2011 and 2010. Planned capital expenditures, including contractual purchase commitments, for the five-year period 2013 – 2017 are expected to total approximately (in millions): $290, $330, $320, $310, and $310, 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, 2012, Vectren's assets related to its qualified pension plans were approximately 82 percent of the projected benefit obligation on a GAAP basis and 115 percent of the target liability for ERISA purposes. Vectren's management currently estimates contributing approximately $10 million to qualified pension plans in 2013. A portion of this funding will be from Utility Holdings and occurs through a routine cash settlement process with its parent.

Contractual Obligations
The following is a summary of contractual obligations at December 31, 2012:

	Total	2013	2014	2015	2016	2017	Thereafter
Long-term debt	$1,208.4	$105.0	$—	$104.8	$13.0	$—	$985.6
Short-term debt	116.7	116.7	—	—	—	—	—
Long-term debt interest commitments	989.0	65.4	62.1	61.5	56.0	55.5	688.5
Plant purchase commitments	3.8	3.8	—	—	—	—	—
Operating leases	2.0	0.8	0.8	0.3	0.1	—	—
Total [(1)]	$2,319.9	$291.7	$62.9	$166.6	$69.1	$55.5	$1,674.1

(1) The Company has other long-term liabilities that total approximately $74 million. This amount is comprised of the following: allocated portions of Vectren's deferred compensation and share-based compensation $24 million, asset retirement obligations $27 million, allocated portions of Vectren's postretirement obligations totaling $11 million, investment tax credits $4 million, environmental remediation $4 million, and other obligations including unrecognized tax benefits totaling $4 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 $373.4 million in 2012, compared to $334.3 million in 2011 and $277.8 million in 2010. The $39.1 million increase in operating cash flow in 2012 compared to 2011 is primarily due to increased earnings, increased cash flow from working capital, and reduced cash needs for contributions to Vectren's pension plans in 2012 compared to 2011. The deferral for future recovery of certain coal costs pursuant to a regulatory order somewhat

offset these increased cash flows and is the primary use of cash impacting the change in noncurrent assets.

The $56.5 million increase in operating cash flow in 2011 compared to 2010 is primarily due to a much greater level of cash funding working capital in 2010. This increase was partially offset by higher level of employer contributions to pension and postretirement plans in 2011 compared to 2010.

Tax payments in the periods presented were favorably impacted by federal legislation extending bonus depreciation and a change in the tax method for recognizing repair and maintenance activities. Federal legislation allowing bonus depreciation on qualifying capital expenditures was increased to 100 percent for 2011, 50 percent for 2012, and continues at 50 percent for 2013. A significant portion of the Company's capital expenditures qualify for this bonus treatment.

Financing Cash Flow
Net cash flow required for financing activities was $121.1 million, $95.0 million, and $54.4 million during the years ending December 31, 2012, 2011, and 2010, respectively. Financing activity reflects the Company's utilization of the long-term capital markets in the current low interest rate environment. Since 2010, the Company has refinanced at lower rates approximately $350 million of maturing or callable long-term debt. These lower rates began to favorably impact interest expense in the fourth quarter of 2011, and more noticeably decreased interest expense in 2012. The Company's operating cash flow funded 100 percent of capital expenditures and dividends in 2012 and 2011 and over 85 percent in 2010. Recently completed long-term financing transactions are more fully described below.

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. As of December 31, 2011, the Company had reclassified $100 million of short-term borrowings as long-term debt to reflect those borrowings were refinanced with the proceeds received. The proceeds received from the issuance of the senior notes were used to refinance VUHI's $96.2 million 5.95 percent senior notes due 2036, that were called at par and retired on Nov. 21, 2011.

On December 20, 2012, Utility Holdings entered into a private placement note purchase agreement pursuant to which institutional investors have agreed to purchase the following tranches of notes: (i) $45 million 3.20% Senior Guaranteed Notes, due June 5, 2028 and (ii) $80 million 4.25% Senior Guaranteed Notes, due June 5, 2043. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. Subject to the satisfaction of customary conditions precedent, this financing is scheduled to close on or about June 5, 2013. The proceeds received from the issuance of these notes will be used to refinance existing indebtedness that matures or is callable in 2013 and for general corporate purposes.

Utility Holdings 2011 Debt Issuance
On November 30, 2011, Utility Holdings closed a financing under a private placement note purchase agreement pursuant to which various institutional investors purchased the following tranches of notes: (i) $55 million of 4.67 percent Senior Guaranteed Notes, due November 30, 2021, (ii) $60 million of 5.02 percent Senior Guaranteed Notes, due November 30, 2026, and (iii) $35 million of 5.99 percent Senior Guaranteed Notes, due December 2, 2041. 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 $148.9 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. Proceeds received from the issuance were used to partially refinance $250 million of VUHI long-term debt with an interest rate of 6.625 percent that matured December 1, 2011.

Long-Term Debt Put and Call Provisions

Occasionally, the Company has executed debt agreements that contain put and call provisions that can be exercised on various dates before maturity. As an example, certain of these issuances could be put to the Company upon the death of the holder (death puts) or at specific dates. During 2012, the Company repaid an insignificant amount related to death puts. During 2011, and 2010, the Company repaid approximately $0.8 million and $1.8 million, respectively, related to death puts. On February 4, 2013, the Company notified holders of Utility Holdings $121.6 million 6.25 percent senior unsecured notes due 2039, which contained both a put and call provision, of its intent to call the debt at par on April 1, 2013. These notes are the only issue outstanding at December 31, 2012 with a put provision.

On November 21, 2011, the Company exercised a call option on Utility Holdings' $96.2 million 5.95 percent senior notes due 2036.

Investing Cash Flow

Cash flow required for investing activities was $245.0 million in 2012, $235.7 million in 2011, and $227.2 million in 2010. Capital expenditures are the primary component of investing activities and totaled $247.6 million in 2012, compared to $235.3 million in 2011 and $229.1 million in 2010. The $12.3 million increase in capital expenditures in 2012 compared to 2011 primarily reflects greater expenditures for bare steel/cast iron replacement and regional electric transmission projects. Increased capital expenditures in 2011 compared to 2010 primarily related to bare steel/cast iron replacement projects.

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 fossil fuel 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 Vectren’s facilities, operations, financial condition and results of operations.
- Increased competition in the energy industry, including the effects of industry restructuring and unbundling.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under traditional 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 and electricity; impacts on both gas and electric large customers; lower residential and commercial customer counts; and higher operating expenses.
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- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, interest rate, and warranty risks.
- 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 mergers, 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 state and federal 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 performance of projects undertaken by Vectren's nonutility businesses and the success of efforts to invest in and develop new opportunities, including but not limited to, Vectren's coal mining, gas marketing, and energy infrastructure strategies.

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. QUALITATIVE & QUANTITATIVE 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 use of derivatives. The Company executes derivative contracts in the normal course of operations while buying and selling commodities and occasionally when managing interest rate risk.

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

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. The Company recently began purchasing call options that are designed to cap gas costs on approximately 70 percent of peak winter delivery periods. Such contracts are generally short-term in nature and are insignificant in terms of value and volume at December 31, 2012. However, it is possible that the utilization of these instruments may grow in the future.

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 market sensitive derivative positions were outstanding on December 31, 2012 and 2011.

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. In the past, the Company also used derivative financial instruments to hedge this risk, but no such derivative instruments were outstanding at December 31, 2012 or 2011.

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. However, this targeted range may not always be attained during the seasonal increases in short-term borrowings. To manage this exposure, the Company may use derivative financial instruments. There were no financial derivatives outstanding at December 31. 2012.

Market risk is estimated as the potential impact resulting from fluctuations in interest rates on adjustable rate borrowing arrangements exposed to short-term interest rate volatility. During 2012 and 2011, the weighted average combined borrowings under these arrangements approximated $119 million and $81 million, respectively. At December 31, 2012, combined borrowings under these arrangements were $158 million. As of December 31, 2011, combined borrowings under these arrangements were $284 million, which excludes the impact of a $100 million long-term debt issuance occurring February 2012. Based upon average borrowing rates under these facilities during the years ended December 31, 2012 and 2011, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by $1.2 million and $0.8 million, respectively.

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 from gas and electric sales and gas transportation services 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 is mitigated by regulatory orders that allow recovery of all uncollectible accounts expense in Ohio and the gas cost portion of uncollectible accounts expense in Indiana based on historical experience.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

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

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

These consolidated financial statements are also subject to an evaluation of internal control over financial reporting conducted under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer. Based on that evaluation, conducted under the framework in Internal Control — Integrated Framework 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, 2012. Management certified this in its Sarbanes Oxley Section 302 certifications, which are attached as exhibits to this 2012 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") (a wholly owned subsidiary of Vectren Corporation) as of December 31, 2012 and 2011, 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, 2012. Our audits also included the financial statement schedule included 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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 1, 2013

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

	At December 31,	
	2012	2011
ASSETS		
Current Assets		
Cash & cash equivalents	$13.3	$6.0
Accounts receivable - less reserves of $5.0 & $5.9, respectively	81.8	95.5
Receivables due from other Vectren companies	—	0.2
Accrued unbilled revenues	93.6	90.8
Inventories	114.0	132.5
Recoverable fuel & natural gas costs	25.3	12.4
Prepayments & other current assets	52.3	69.3
Total current assets	380.3	406.7
Utility Plant		
Original cost	5,176.8	4,979.9
Less: accumulated depreciation & amortization	2,057.2	1,947.3
Net utility plant	3,119.6	3,032.6
Investments in unconsolidated affiliates	0.2	0.2
Other investments	32.6	31.8
Nonutility plant - net	146.9	156.6
Goodwill - net	205.0	205.0
Regulatory assets	126.5	100.0
Other assets	35.7	41.6
TOTAL ASSETS	$4,046.8	$3,974.5

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,	
	2012	2011
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$121.0	$112.9
Accounts payable to affiliated companies	29.7	36.8
Payables to other Vectren companies	25.1	30.1
Accrued liabilities	139.3	121.0
Short-term borrowings	116.7	142.8
Current maturities of long-term debt	105.0	—
Total current liabilities	536.8	443.6
Long-Term Debt - Net of Current Maturities	1,103.4	1,208.2
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	578.5	537.5
Regulatory liabilities	364.2	345.2
Deferred credits & other liabilities	73.9	93.4
Total deferred credits & other liabilities	1,016.6	976.1
Commitments & Contingencies (Notes 8-10)		
Common Shareholder's Equity		
Common stock (no par value)	781.6	774.6
Retained earnings	608.4	572.0
Total common shareholder's equity	1,390.0	1,346.6
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$4,046.8	$3,974.5

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,		
	2012	2011	2010
OPERATING REVENUES			
Gas utility	$738.1	$819.1	$954.1
Electric utility	594.9	635.9	608.0
Other	0.6	2.0	1.6
Total operating revenues	1,333.6	1,457.0	1,563.7
OPERATING EXPENSES			
Cost of gas sold	301.3	375.4	504.7
Cost of fuel & purchased power	192.0	240.4	235.0
Other operating	310.1	313.1	299.2
Depreciation & amortization	190.0	192.3	188.2
Taxes other than income taxes	53.4	54.0	59.6
Total operating expenses	1,046.8	1,175.2	1,286.7
OPERATING INCOME	286.8	281.8	277.0
Other income - net	8.0	4.3	5.4
Interest expense	71.5	80.3	81.4
INCOME BEFORE INCOME TAXES	223.3	205.8	201.0
Income taxes	85.3	82.9	77.1
NET INCOME	$138.0	$122.9	$123.9

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

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

	Year Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$138.0	$122.9	$123.9
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	190.0	192.3	188.2
Deferred income taxes & investment tax credits	72.3	64.6	71.2
Expense portion of pension & postretirement periodic benefit cost	5.0	4.6	4.1
Provision for uncollectible accounts	7.4	11.4	16.2
Other non-cash expense - net	5.6	11.0	12.4
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenue	3.7	36.7	(26.6)
Inventories	18.5	(15.0)	(7.3)
Recoverable/refundable fuel & natural gas costs	(12.9)	(4.5)	(30.2)
Prepayments & other current assets	2.6	28.2	(31.3)
Accounts payable, including to Vectren companies & affiliated companies	(7.4)	(50.3)	(6.7)
Accrued liabilities	(1.6)	(14.8)	6.4
Changes in noncurrent assets	(33.2)	(46.5)	(7.8)
Changes in noncurrent liabilities	(14.6)	(6.3)	(34.7)
Net cash flows from operating activities	373.4	334.3	277.8
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt - net of issuance costs	99.5	148.9	—
Additional capital contribution	7.0	—	4.7
Requirements for:			
Dividends to parent	(101.5)	(91.6)	(87.9)
Retirement of long-term debt	—	(347.0)	(1.8)
Other financing activities	—	(1.1)	—
Net change in short-term borrowings	(126.1)	195.8	30.6
Net cash flows from financing activities	(121.1)	(95.0)	(54.4)
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from other investing activities	2.6	0.4	3.0
Requirements for:			
Capital expenditures, excluding AFUDC equity	(247.6)	(235.3)	(229.1)
Other investments	—	(0.8)	(1.1)
Net cash flows from investing activities	(245.0)	(235.7)	(227.2)
Net change in cash & cash equivalents	7.3	3.6	(3.8)
Cash & cash equivalents at beginning of period	6.0	2.4	6.2
Cash & cash equivalents at end of period	$13.3	$6.0	$2.4

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

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

	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance at January 1, 2010	$769.9	$504.7	$0.1	$1,274.7
Net income		123.9		123.9
Common stock:				
Additional capital contribution	4.7			4.7
Dividends		(87.9)		(87.9)
Balance at December 31, 2010	774.6	540.7	0.1	1,315.4
Net income		122.9		122.9
Other comprehensive income			(0.1)	(0.1)
Common stock:				
Dividends		(91.6)		(91.6)
Balance at December 31, 2011	774.6	572.0	—	1,346.6
Net income		138.0		138.0
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

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 & Nature of Operations

Vectren Utility Holdings, Inc. (the Company or Utility Holdings), 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 or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. 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 566,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 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 310,000 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 related to the Company’s regulated operations is valued at historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

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

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

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

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

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

Impairment Reviews
Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate 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 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

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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 and certain asbestos-related issues 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 from ProLiance and others, 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 Midwest and maintains operational control over the Company's electric transmission facilities as well as that of other Midwest utilities. 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 \$26.9 million in 2012, \$29.0 million in 2011, and \$33.6 million in 2010. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

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 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)	2012		2011	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$2,614.3	3.5 %	$2,516.8	3.5 %
Electric utility plant	2,463.6	3.3 %	2,316.8	3.3 %
Common utility plant	52.0	3.0 %	51.6	2.9 %
Construction work in progress	46.9	—	94.7	—
Total original cost	$5,176.8		$4,979.9	

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, 2012, is $185.9 million with accumulated depreciation totaling $78.9 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)	2012	2011
Computer hardware & software	$96.6	$101.3
Land & buildings	38.6	40.0
All other	11.7	15.3
Nonutility plant - net	$146.9	$156.6

Nonutility plant is presented net of accumulated depreciation and amortization totaling $201.5 million and $188.8 million as of December 31, 2012 and 2011, respectively. For the years ended December 31, 2012, 2011, and 2010, the Company capitalized interest totaling $0.2 million, $0.3 million, and $0.2 million, respectively, on nonutility plant construction projects.

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4. Regulatory Assets & Liabilities

Regulatory Assets
Regulatory assets consist of the following:

	At December 31,	
(In millions)	2012	2011
Future amounts recoverable from ratepayers related to:		
Deferred income taxes (See Note 5)	$ (3.9)	$ 1.3
Asset retirement obligations & other	2.6	2.3
	(1.3)	3.6
Amounts deferred for future recovery related to:		
Deferred coal costs (See Note 9)	42.4	17.7
Cost recovery riders & other	10.2	6.4
	52.6	24.1
Amounts currently recovered in customer rates related to:		
Unamortized debt issue costs & hedging proceeds	32.6	34.3
Demand side management programs	4.4	6.3
Indiana authorized trackers	32.1	24.3
Ohio authorized trackers	1.5	1.0
Premiums paid to reacquire debt	2.7	3.3
Other base rate recoveries	1.9	3.1
	75.2	72.3
Total regulatory assets	$ 126.5	$ 100.0

Of the $75.2 million currently being recovered in customer rates, $4.4 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 $41.6 million, is 18 years. The remainder of the regulatory assets are being recovered timely through tracking 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, 2012 and 2011, the Company has $364.2 million and $345.2 million, respectively, in Regulatory liabilities. Of these amounts, $349.5 million and $320.9 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 Fuels, Inc.
Vectren Fuels, Inc., a wholly owned subsidiary of Vectren, owns coal mines from which SIGECO purchases coal used for electric generation. The price of coal that is charged by Vectren Fuels to SIGECO is priced consistent with contracts reviewed by the OUCC and on file with IURC. Amounts purchased for the years ended December 31, 2012, 2011 and 2010, totaled $115.6 million, $144.1 million, and $152.4 million, respectively. Amounts owed to Vectren Fuels at December 31, 2012 and 2011 are included in Payables to other Vectren companies.

Miller Pipeline, LLC
Miller Pipeline, LLC (Miller), a wholly owned subsidiary of Vectren, performs natural gas and water distribution, transmission, and construction repair and rehabilitation primarily in the Midwest and the repair and rehabilitation of

gas, water, and wastewater facilities nationwide. Miller's customers include Utility Holdings' utilities. Fees incurred by Utility Holdings and its subsidiaries totaled $40.9 million in 2012, $43.1 million in 2011, and $24.4 million in 2010. Amounts owed to Miller at December 31, 2012 and 2011 are included in Payables to other Vectren companies.

Minnesota Limited, Inc.
Minnesota Limited, Inc. (Minnesota Limited), a wholly owned subsidiary of Vectren through an acquisition on March 31, 2011, provides transmission pipeline construction and maintenance; pump station, compressor station, terminal and refinery construction; and hydrostatic testing to customers generally in the northern Midwest region. Minnesota Limited's customers include Utility Holdings' utilities. Fees incurred by Utility Holdings and its subsidiaries totaled $5.7 million in 2012. There were no transactions with Minnesota Limited prior to 2012.

Vectren Source
Vectren Source, a former wholly owned and nonutility subsidiary of Vectren that was sold on December 31, 2011, provided natural gas and other related products and services in the Midwest and Northeast United States to approximately 283,000 residential and commercial customers as of the date of sale. This customer base reflected approximately 143,000 customers in VEDO's service territory that had either voluntarily opted to choose their natural gas supplier or were supplied natural gas by Vectren Source but remained customers of the regulated utility as part of VEDO's exit the merchant function process. From January 2010 through the date of sale, Vectren Source sold gas commodity directly to customers in VEDO's service territory and VEDO purchased receivables from Vectren Source to include those sales in one customer bill similar to the receivables purchased from Vectren Source related to customers that voluntarily chose Vectren Source as their supplier. Total receivables purchased from Vectren Source in the year ended December 31, 2011 and 2010 totaled $66.5 million and $54.4 million, respectively.

As part of VEDO's initial phase of exiting the merchant function which ended on March 31, 2010, the Company purchased natural gas from Vectren Source. Such purchases totaled $3.0 million in 2011 and $14.9 million in 2010, which represented approximately 1 percent and 2 percent of the Company's total gas purchased during 2011 and 2010, respectively. Amounts charged by Vectren Source for gas supply services were comprised of the monthly NYMEX settlement price plus a fixed adder, as authorized by the PUCO.

ProLiance Holdings, LLC (ProLiance)
ProLiance, a nonutility energy marketing affiliate of Vectren and Citizens Energy Group (Citizens), provides services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance's customers include the Company's Indiana utilities as well as Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. On March 17, 2011, an order was received by the IURC providing for ProLiance's continued provision of gas supply services to the Company's Indiana utilities and Citizens Energy Group through March 2016.

Purchases from ProLiance for resale and for injections into storage for the years ended December 31, 2012, 2011 and 2010 totaled $274.5 million, $375.7 million, and $426.9 million, respectively. Amounts owed to ProLiance at December 31, 2012 and 2011, for those purchases were $29.7 million and $36.8 million, respectively, and are included in Accounts payable to affiliated companies in the Consolidated Balance Sheets. The Company purchased approximately 97 percent of its gas through ProLiance in 2012, 97 percent in 2011, and 86 percent in 2010. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

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 $44.8 million, $46.1 million, and $47.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Retirement Plans & Other Postretirement Benefits
At December 31, 2012, 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 2012. For the years ended December 31 2011 and 2010, Utility Holdings contributed approximately $33.4 million and $11.6 million, respectively, to Vectren's defined benefit pension plans. Such contributions are made to Vectren in total and are not plan specific. The combined funded status of Vectren's plans was approximately 82 percent at December 31, 2012 and 83 percent at December 31, 2011.

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, 2012, 2011 and 2010, costs totaling $7.2 million, $6.6 million and $5.9 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, 2012 and 2011, $10.7 million and $10.2 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 increased funding of pension plans in 2011, at December 31, 2012 and 2011, the Company has $31.1 million, and $37.8 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, 2012 and 2011, $23.6 million and $27.1 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. The Internal Revenue Service (IRS) has concluded examinations of Vectren's U.S. federal income tax returns for tax years through December 31, 2005. Tax years 2006 and 2008 have recently been examined by the IRS, and such examination resulted in no assessments but is in IRS Joint Committee review currently. The primary focus of the IRS examination was certain repairs and maintenance deductions, an area of particular focus by the IRS throughout the utility industry. In 2012, the IRS suspended all examinations related to this issue generally, resulting in the elimination of the audit risk in this area for Vectren through 2012. To the extent IRS guidance changes in this area, any impact is not expected to be material to the Company's result of operations or financial condition. Further, the Company does not expect any changes to this liability for unrecognized income tax benefits within the next 12 months that would significantly impact the Company's results of operations or financial condition. The State of Indiana, Vectren's primary state tax jurisdiction, has conducted examinations of state income tax returns for tax years through December 31, 2007. The statutes of limitations for assessment of federal income tax have expired with respect to tax years through 2005 and through 2008 for Indiana income tax.

Pursuant to a subsidiary tax sharing agreement and for financial reporting purposes, the Company's subsidiaries, which are regulated utilities, record income taxes on a separate company basis. The Company's allocated share of tax effects resulting from it being a part of Vectren's consolidated tax group are recorded at the parent company level. Current taxes payable/receivable are settled with Vectren in cash.

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.

Indiana House Bill 1004
In May 2011, House Bill 1004 was signed into law. This legislation phases in over four years a two percent rate reduction to the Indiana Adjusted Gross Income Tax for corporations. Pursuant to House Bill 1004, the tax rate will be lowered by one-half percent each year beginning on July 1, 2012, to the final rate of six and one-half percent effective July 1, 2015. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the second quarter of 2011, the period of enactment. The impact was not material to results of operations or financial condition as the decrease in Deferred tax liabilities was generally offset by a $17.1 million decrease in Regulatory assets.

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

	Year Ended December 31,		
(In millions)	2012	2011	2010
Current:			
Federal	$6.1	$10.4	$(0.7)
State	6.9	7.9	6.6
Total current taxes	13.0	18.3	5.9
Deferred:			
Federal	68.7	58.6	67.6
State	4.2	6.6	4.4
Total deferred taxes	72.9	65.2	72.0
Amortization of investment tax credits	(0.6)	(0.6)	(0.8)
Total income tax expense	$85.3	$82.9	$77.1

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

	Year Ended December 31,		
	2012	2011	2010
Statutory rate	35.0 %	35.0 %	35.0 %
State and local taxes-net of federal benefit	3.7	3.9	3.8
Amortization of investment tax credit	(0.3)	(0.3)	(0.4)
State apportionment impacts	—	0.9	—
Adjustment of income tax accruals	(0.2)	0.6	—
All other - net	—	0.2	—
Effective tax rate	38.2 %	40.3 %	38.4 %

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2012	2011
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$597.1	$551.8
Regulatory assets recoverable through future rates	23.5	25.1
Alternative minimum tax carryforward	(44.0)	(35.0)
Employee benefit obligations	13.4	11.3
Regulatory liabilities to be settled through future rates	(18.3)	(17.2)
Other – net	6.8	1.5
Net noncurrent deferred tax liability	578.5	537.5
Current deferred tax liabilities (assets):		
Deferred fuel costs - net	25.7	6.0
Alternative minimum tax carryforward	(2.7)	(15.6)
Demand side management programs	2.7	0.7
Other – net	(5.9)	(5.4)
Net current deferred tax liability (asset)	19.8	(14.3)
Net deferred tax liability	$598.3	$523.2

At December 31, 2012 and 2011, investment tax credits totaling $3.8 million and $4.4 million, respectively, are included in Deferred credits & other liabilities. At December 31, 2012, the Company has alternative minimum tax carryforwards of $46.7 million, which do not expire.

Uncertain Tax Positions

Following is a roll forward of the total amount of unrecognized tax benefits for the three years ended December 31, 2012:

(In millions)	2012	2011	2010
Unrecognized tax benefits at January 1	$11.0	$11.8	$9.5
Gross increases - tax positions in prior periods	0.1	3.3	1.5
Gross decreases - tax positions in prior periods	(9.3)	(4.4)	(0.2)
Gross increases - current period tax positions	1.9	0.6	1.0
Settlements	—	(0.3)	—
Unrecognized tax benefits at December 31	$3.7	$11.0	$11.8

Of the change in unrecognized tax benefits during 2012, 2011, and 2010, almost none impacted the effective rate. The amount of unrecognized tax benefits, which if recognized, that would impact the effective tax rate was almost none at December 31, 2012 , 2011, and 2010. As of December 31, 2012, the unrecognized tax benefit relates to tax positions for which the ultimate deductibility is more likely than not but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority. Thus, it is not expected that any changes to these tax positions would have a significant impact on earnings.

The Company recognized income related to a reversal of interest expense previously accrued and net of penalties totaling $0.7 million in 2012, and recognized expense related to interest and penalties totaling approximately $0.4 million in 2011, and $0.3 million in 2010. The Company had approximately $0.2 million and $0.9 million for the payment of interest and penalties accrued as of December 31, 2012 and 2011, respectively.

The net liability on the Consolidated Balance Sheet for unrecognized tax benefits inclusive of interest, penalties and net of secondary impacts which are a component of the Deferred income taxes and are benefits, totaled $3.6 million and $10.8 million, respectively, at December 31, 2012 and 2011.

6. Borrowing Arrangements

Short-Term Borrowings

At December 31, 2012, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2012, approximately $233 million was available. This short-term credit facility was renewed in November 2011 and is available through September 2016. 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)	2012		2011		2010	
Year End						
Balance Outstanding	$116.7		$242.8		$47.0	
Weighted Average Interest Rate	0.40	%	0.57	%	0.41	%
Annual Average						
Balance Outstanding	$77.6		$39.6		$14.0	
Weighted Average Interest Rate	0.47	%	0.48	%	0.40	%
Maximum Month End Balance Outstanding	$214.2		$242.8		$47.0	

Throughout 2012, 2011, and most of 2010, 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)	2012	2011
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2013, 5.25%	$100.0	$100.0
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
2026, 5.02%	60.0	60.0
2035, 6.10%	75.0	75.0
2039, 6.25%	121.6	121.6
2041, 5.99%	35.0	35.0
2042, 5.00%	100.0	—
Total Utility Holdings	821.6	721.6
SIGECO		
First Mortgage Bonds		
2015, 1985 Pollution Control Series A, current adjustable rate 0.15%, tax exempt, 2012 weighted average: 0.17%	9.8	9.8
2016, 1986 Series, 8.875%	13.0	13.0
2020, 1998 Pollution Control Series B, 4.50%, tax exempt	4.6	4.6
2023, 1993 Environmental Improvement Series B, 5.15%, tax exempt	22.6	22.6
2024, 2000 Environmental Improvement Series A, 4.65%, tax exempt	22.5	22.5
2025, 1998 Pollution Control Series A, current adjustable rate 0.15%, tax exempt, 2012 weighted average: 0.16%	31.5	31.5
2029, 1999 Series, 6.72%	80.0	80.0
2030, 1998 Pollution Control Series B, 5.00%, tax exempt	22.0	22.0
2030, 1998 Pollution Control Series C, 5.35%, tax exempt	22.2	22.2
2040, 2009 Environmental Improvement Series, 5.40%, tax exempt	22.3	22.3
2041, 2007 Pollution Control Series, 5.45%, tax exempt	17.0	17.0
Total SIGECO	267.5	267.5
Indiana Gas		
Senior Unsecured Notes		
2013, Series E, 6.69%	5.0	5.0
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	121.0	121.0

Total long-term debt outstanding	1,210.1	1,110.1
Current maturities of long-term debt	(105.0)	—
Short-term borrowings refinanced in 2012	—	100.0
Unamortized debt premium & discount - net	(1.7)	(1.9)
Total long-term debt-net	$1,103.4	$1,208.2

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. As of December 31, 2011, the Company had reclassified $100 million of short-term borrowings as long-term debt to reflect those borrowings were refinanced with the proceeds received. The proceeds received from the issuance of the senior notes were used to refinance VUHI's $96.2 million 5.95 percent senior notes due 2036, that were called at par and retired on Nov. 21, 2011.

On December 20, 2012, Utility Holdings entered into a private placement note purchase agreement pursuant to which institutional investors have agreed to purchase 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. The notes will be unconditionally guaranteed by Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company and Vectren Energy Delivery of Ohio, Inc. Subject to the satisfaction of customary conditions precedent, this financing is scheduled to close on or about June 5, 2013. The proceeds received from the issuance of these notes will be used to refinance existing indebtedness that matures or is callable in 2013 and for general corporate purposes.

Utility Holdings 2011 Debt Issuance

On November 30, 2011, Utility Holdings closed a financing under a private placement note purchase agreement pursuant to which various institutional investors purchased the following tranches of notes: (i) $55.0 million of 4.67 percent Senior Guaranteed Notes, due November 30, 2021, (ii) $60 million of 5.02 percent Senior Guaranteed Notes, due November 30, 2026, and (iii) $35 million of 5.99 percent Senior Guaranteed Notes, due December 2, 2041. 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 $149 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.

Long-Term Debt Puts & Calls

Occasionally, the Company has executed debt agreements that contain put and call provisions that can be exercised on various dates before maturity. As an example, certain of these issuances could be put to the Company upon the death of the holder (death puts) or at specific dates. During 2012, the Company repaid an insignificant amount related to death puts. During 2011, and 2010, the Company repaid approximately $0.8 million and $1.8 million, respectively, related to death puts. On February 4, 2013, the Company notified holders of Utility Holdings $121.6 million 6.25 percent senior unsecured notes due 2039, which contained both a put and call provision, of its intent to call the debt at par on April 1, 2013. These notes are the only issue outstanding at December 31, 2012 with a put provision.

On November 21, 2011, the Company exercised a call option on Utility Holdings' $96.2 million 5.95 percent senior notes due 2036.

Letters of Credit Supporting Long-Term Debt

As of December 31, 2012, the Company has letters of credit outstanding in support of two SIGECO tax exempt adjustable rate first mortgage bonds totaling $41.7 million. In the unlikely event the letters of credit were called, the Company could settle with the financial institutions supporting these letters of credit with general assets or by drawing from the credit line that expires in September of 2016. Due to the long-term nature of the credit agreement, such debt is classified as long-term at December 31, 2012. As of December 31, 2012, other than the letters of credit discussed, the Company does not have any material off balance sheet arrangements.

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 2012 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2012 is excluded from Current liabilities in the Consolidated Balance Sheets. At December 31, 2012, $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 $2.8 billion at December 31, 2012.

Consolidated maturities of long-term debt during the years following 2012 (in millions) are $105.0 in 2013, zero in 2014, $104.8 in 2015, $13.0 in 2016, zero in 2017, and $985.6 thereafter.

Debt Guarantees
Utility Holdings’ currently outstanding long-term and short-term debt is jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. Utility Holdings’ long-term debt and short-term debt outstanding at December 31, 2012, totaled $821 million and $117 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 and interest coverage, 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, 2012, the Company was in compliance with all debt covenants.

7. Common Shareholder’s Equity

During the years ended December 31, 2012, 2011, and 2010, the Company has cumulatively received additional capital of $11.7 million from Vectren which was funded by new share issues from Vectren’s dividend reinvestment plan and other stock plans.

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 2012 and thereafter (in millions) are $0.8 in 2013, $0.8 in 2014, $0.3 in 2015, $0.1 in 2016, and zero thereafter. Total lease expense (in millions) was $1.2 in 2012, $0.6 in 2011, and $0.7 in 2010. Firm purchase commitments for utility plant total $3.8 million in 2013 and zero in 2014 and 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. 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. 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 replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and operational improvement. In 2011, laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects, and in Ohio other capital investment projects, outside of a base rate proceeding. Utilization of these recovery mechanisms is discussed below.

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 upon 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 recovered through the DRR. To date, the Company has made capital investments under this rider totaling $80 million. During 2012, 2011, and 2010 gas operating revenues associated with the DRR were $6.5 million, $3.6 million, and $1.4 million, respectively. Other Income associated with the debt-related post in service carrying costs totaled $1.8 million, $2.0 million, and $0.9 million for 2012, 2011, and 2010, respectively. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $6.5 million, $3.0 million, and $1.0 million at December 31, 2012, 2011, and 2010, respectively.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. Once such application is approved, the legislation authorizes a deferral of costs, such as depreciation, property taxes, and debt-related carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law. The order provides for the deferral of depreciation, debt-related post in service carrying costs, and property taxes for its $23.5 million capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. The order created a regulatory asset as of December 31, 2012 of $1.5 million, of which $0.9 million is Other Income related to the accrual of post in service carrying costs, and the remaining $0.6 million is the deferral of depreciation and property tax expense. The Company expects to make a future request for similar accounting authority on its capital expenditure program for the calendar year 2013.

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 Vectren North and $3 million annually at Vectren South. For USGAAP accounting purposes only the debt-related post in service carrying costs are recognized in the Consolidated Statements of Income currently. Such deferral is limited by individual qualifying project to three years after being placed into service at Vectren South and four years after being placed into service at Vectren North. The debt-related post in service rate used to calculate the deferral is based on a current cost of funds. At December 31, 2012 and 2011, the Company has USGAAP regulatory assets totaling $8.5 million and $4.7 million, respectively, associated with the deferral of

depreciation and debt-related post in service carrying cost activities.

In April 2011, 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 are to be deferred for future recovery in the utility's next general rate case. To date, the Company has not initiated a filing requesting authority to recover costs using the Senate Bill 251 approach and continues to study its applicability to expenditures associated with its natural gas distribution operations.

Pipeline Safety Law
On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years Those regulations may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the law is expected to result 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. Operating expenses associated with expanded compliance requirements may grow by approximately $9 million annually, with $6 million attributable to the Indiana operations. Related to the Indiana operations, the Company expects to seek recovery under Senate Bill 251, or such costs may be recoverable through current tracking mechanisms. Capital investments, associated with the Pipeline Safety Law, are expected to be significant. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 or other currently authorized recovery mechanisms, such as the Distribution Replacement Rider, in Ohio.

Vectren South Electric Base Rate Filing
On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. The IURC issued an order in the case on April 27, 2011. The order provided for a revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent, and an overall rate of return of 7.29 percent. The new rates were effective May 3, 2011. The IURC, in its order, provided for deferred accounting treatment related to the Company's estimated $32 million investment in dense pack technology, of which approximately $25.5 million has been invested as of December 31, 2012. In addition, the IURC denied the Company’s request for implementation of the decoupled rate design, which is discussed further below. Addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions would be initiated.

Coal Procurement Procedures
Vectren South submitted a request for proposal (RFP) in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the electric rate case, a sub docket proceeding was established to review the Company’s prospective coal procurement procedures, and the Company submitted evidence related to its 2011 RFP. In March 2012, the IURC issued its order in the sub docket which concluded that Vectren South’s 2011 RFP process resulted in the lowest fuel cost reasonably possible. In late 2012, Vectren South terminated its contract with one of the suppliers due to coal quality issues that were identified during test burns of the coal. In addition to coal purchased under these contracts, Vectren South has also

contracted with Vectren Fuels, Inc. to purchase lower priced spot coal. This spot purchase was found to be reasonable in a recent FAC order. The IURC will continue to regularly monitor Vectren South’s procurement process in future fuel adjustment proceedings.

Delivery to Vectren's power plants of lower-priced contract coal from the April 2011 RFP process began during 2012. On December 5, 2011 within the quarterly FAC filing, Vectren South 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 these new term contracts effective after

2012. The cost difference will be deferred to a regulatory asset and 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. The deferred amount includes a reduction in the value of the coal inventory at December 31, 2011 of approximately $17.7 million to reflect existing coal inventory at the new, lower price. Deferrals related to coal purchases in 2012 have totaled approximately $24.7 million, bringing the total deferred balance as of December 31, 2012, to the expected level of $42.4 million.

Vectren South Electric Demand Side Management Program Filing
On August 16, 2010, Vectren South filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South 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 discussed earlier.

Vectren North Pipeline Safety Investigation
On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. The Company seeks further clarity on the scope of the requirement and the ability to also use contractors to perform certain inspections. A schedule for the rehearing proceeding will be set in March 2013.

Vectren North & Vectren South Gas Decoupling Extension Filing
On April 14, 2011, the Company's Indiana based gas companies (Vectren North and Vectren South) filed with the IURC a joint settlement agreement with the OUCC on an extension of the offering of conservation programs and the supporting gas decoupling mechanism originally approved in December 2006. On August 18, 2011, the IURC issued an order approving the settlement as filed, granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015.

VEDO Gas Rate Design

The rate design approved by the PUCO on January 7, 2009, and initially implemented on February 22, 2009, allowed for the phased movement toward a straight fixed variable rate design, which places substantially all of the fixed cost recovery in the monthly customer service charge. This rate design mitigates most weather risk as well as the effects of declining usage, similar to the company's lost margin recovery mechanism in place in the Indiana natural gas service territories and the mechanism in place in Ohio prior to this rate order. Since the straight fixed variable rate design was fully implemented for residential base rates in February 2010, nearly 90 percent of the combined residential and commercial base rate gas margins were recovered through the customer service charge. As a result, some margin previously recovered during the peak delivery winter months, such as January and the first half of February 2010, is more ratably recognized throughout the year.

VEDO Continues the Process to Exit the Merchant Function
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.

10. Environmental Matters

Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting Vectren South's electric operations. The Company is currently evaluating the impact Senate Bill 251 may have on its operations, including applicability to 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
Clean Air Interstate Rule / 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 SO_2 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 SO_2 and NOx allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSAPR set individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances to generating units through state implementation plans, CSAPR allowances were allocated to individual units directly through the federal rule. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. Multiple administrative and judicial challenges were filed. On December 30, 2011, the Court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the Court vacated CSAPR and directed the EPA to continue to administer CAIR. In October 2012, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. EPA's request for rehearing was denied by the Court on January 24, 2013. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air Regulations").

Mercury and Air Toxics (MATS) Rule
On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule is the EPA’s response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR's implementation by the Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA also recently announced it will reconsider MATS requirements for new construction. Such requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology.

Conclusions Regarding Air Regulations

To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, 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 Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). 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 new 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 SO_2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO_2 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.

The Company is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule and the 2015 requirement imposed by CAIR. Based upon an initial review, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment. However, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required and could be significant depending on the required method of compliance with the requirements. While the Company has not yet quantified what the additional costs may be associated with these efforts, because the compliance is required by government regulation the Company believes that such additional costs, if incurred, should be recoverable under Indiana Senate Bill 251 referenced above.

Notice of Violation Received

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements. At this time the Company is reviewing the potential impact this NOV could have on capital expenditures and operating costs. To the extent costs to comply increase, they should be recoverable under Indiana law.

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in 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. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized, the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2013. Depending on the final rule and on the Company's facts and circumstances, capital investments could approximate $40 million if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. 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. EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. EPA is under an April 19, 2013 deadline to complete its rule proposal. 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 recovered under Senate Bill 251 referenced above.

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 by-products 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. Rules have not been finalized given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company's ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as$30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase 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 recovered under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas 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 greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. EPA's PSD and Title V permitting rules for GHG's were recently upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards for greenhouse gases for new electric generating facilities under Clean Air Act Section 111(b). While standards for new sources are not yet final, EPA has signaled its intent to propose New Source Performance Standards for greenhouse gases for existing electric generating units under Section 111(d), which would be applicable to the Company's existing units. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown

If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other greenhouse gases 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 greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas 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 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. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. The financial incentives include an enhanced return on equity and tracking mechanisms to recover program costs. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2009, the Company also executed a long term purchase power commitment for 50 MW of wind energy. These transactions supplement a 30 MW wind energy purchase power agreement executed in 2008. Before the impacts of efficiency measures which are defined as clean energy in the legislation, the Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment. The Company continues to evaluate whether to participate in this voluntary program.

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 $41.7 million ($23.2 million at Indiana Gas and $18.5 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 million of the expected $15 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, 2012 and 2011, approximately $4.6 million and $6.5 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to both the Indiana Gas and

SIGECO sites.

11. Fair Value Measurements

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

	At December 31,			
	2012		2011	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,208.4	$1,372.6	$1,208.2	$1,345.7
Short-term borrowings	116.7	116.7	142.8	142.8
Cash & cash equivalents	13.3	13.3	6.0	6.0

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.

12. Segment Reporting

The Company’s operations consist of regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio. The Electric Utility Services segment provides electric distribution services primarily to southwestern Indiana, and includes the Company’s power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Company is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other 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)	2012	2011	2010
Revenues			
Gas Utility Services	$738.1	$819.1	$954.1
Electric Utility Services	594.9	635.9	608.0
Other Operations	40.1	43.9	44.5
Eliminations	(39.5)	(41.9)	(42.9)
Total revenues	$1,333.6	$1,457.0	$1,563.7
Profitability Measure - Net Income			
Gas Utility Services	$60.0	$52.5	$53.7
Electric Utility Services	68.0	65.0	60.9
Other Operations	10.0	5.4	9.3
Total net income	$138.0	$122.9	$123.9
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Gas Utility Services	$85.4	$84.3	$80.7
Electric Utility Services	81.3	80.2	80.8
Other Operations	23.3	27.8	26.7
Total depreciation & amortization	$190.0	$192.3	$188.2
Interest Expense			
Gas Utility Services	$31.8	$37.1	$38.8
Electric Utility Services	33.8	36.4	36.4
Other Operations	5.9	6.8	6.2
Total interest expense	$71.5	$80.3	$81.4
Income Taxes			
Gas Utility Services	$39.1	$34.5	$35.1
Electric Utility Services	46.4	45.3	40.8
Other Operations	(0.2)	3.1	1.2
Total income taxes	$85.3	$82.9	$77.1
Capital Expenditures			
Gas Utility Services	$128.8	$113.5	$88.7
Electric Utility Services	108.8	102.2	120.1
Other Operations	16.2	17.8	22.5
Non-cash costs & changes in accruals	(6.2)	1.8	(2.2)
Total capital expenditures	$247.6	$235.3	$229.1

	At December 31,		
(In millions)	2012	2011	2010
Assets			
Gas Utility Services	$2,173.5	$2,125.2	$2,161.7
Electric Utility Services	1,705.1	1,656.5	1,666.5
Other Operations, net of eliminations	168.2	192.8	96.3
Total assets	$4,046.8	$3,974.5	$3,924.5

13. Additional Balance Sheet & Operational Information

Inventories consist of the following:

	At December 31,	
(In millions)	2012	2011
Gas in storage – at LIFO cost	$22.4	$31.8
Materials & supplies	38.4	38.6
Coal & oil for electric generation - at average cost	52.0	60.6
Other	1.2	1.5
Total inventories	$114.0	$132.5

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 both December 31, 2012, and 2011, by approximately $12 million.

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

	At December 31,	
(In millions)	2012	2011
Prepaid gas delivery service	$28.5	$42.4
Prepaid taxes	21.1	5.1
Deferred income taxes	—	14.3
Other prepayments & current assets	2.7	7.5
Total prepayments & other current assets	$52.3	$69.3

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

	At December 31,	
(In millions)	2012	2011
Cash surrender value of life insurance policies	$27.4	$25.9
Municipal bond	3.6	3.9
Restricted cash & other investments	1.6	2.0
Total other investments	$32.6	$31.8

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

	At December 31,	
(In millions)	2012	2011
Refunds to customers & customer deposits	$53.1	$56.4
Accrued taxes	30.7	29.9
Accrued interest	19.4	17.5
Deferred income taxes	19.8	—
Accrued salaries & other	16.3	17.2
Total accrued liabilities	$139.3	$121.0

Asset retirement obligations included in the Consolidated Balance Sheets roll forward as follows:

(In millions)	2012	2011
Asset retirement obligation, January 1	$34.0	$32.0
Accretion	2.2	2.0
Changes in estimates, net of cash payments	(8.9)	—
Asset retirement obligation, December 31	27.3	34.0
Accrued liabilities	$—	$0.2
Deferred credits & other liabilities	$27.3	$33.8

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

	Year Ended December 31,		
(In millions)	2012	2011	2010
AFUDC - borrowed funds	$4.6	$2.5	$1.4
AFUDC - equity funds	0.4	0.2	0.3
Nonutility plant capitalized interest	0.2	0.3	0.2
Interest income	0.6	0.6	0.6
Cash surrender value of life insurance policies	1.4	0.1	1.8
Other income	0.8	0.6	1.1
Total other – net	$8.0	$4.3	$5.4

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2012	2011	2010
Cash paid (received) for:			
Interest	$69.6	$82.5	$81.4
Income taxes	30.1	(3.4)	25.4

As of December 31, 2012 and 2011, the Company has accruals related to utility and nonutility plant purchases totaling approximately $7.1 million and $9.2 million, respectively.

14. 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 $117 million is outstanding at December 31, 2012, and Utility Holdings' $821 million unsecured senior notes outstanding at December 31, 2012. 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, 2012 (in millions):

	Subsidiary Guarantors	Parent Company	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

Consolidating Statement of Income for the year ended December 31, 2011 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$819.1	$—	$—	$819.1
Electric utility	635.9	—	—	635.9
Other	—	43.9	(41.9)	2.0
Total operating revenues	1,455.0	43.9	(41.9)	1,457.0
OPERATING EXPENSES				
Cost of gas sold	375.4	—	—	375.4
Cost of fuel & purchased power	240.4	—	—	240.4
Other operating	354.6	—	(41.5)	313.1
Depreciation & amortization	164.6	27.1	0.6	192.3
Taxes other than income taxes	52.3	1.5	0.2	54.0
Total operating expenses	1,187.3	28.6	(40.7)	1,175.2
OPERATING INCOME	267.7	15.3	(1.2)	281.8
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	117.5	(117.5)	—
Other – net	3.1	48.9	(47.7)	4.3
Total other income (expense)	3.1	166.4	(165.2)	4.3
Interest expense	73.5	55.7	(48.9)	80.3
INCOME BEFORE INCOME TAXES	197.3	126.0	(117.5)	205.8
Income taxes	79.8	3.1	—	82.9
NET INCOME	$117.5	$122.9	$(117.5)	$122.9

Consolidating Statement of Income for the year ended December 31, 2010 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$954.1	$—	$—	$954.1
Electric utility	608.0	—	—	608.0
Other	—	44.5	(42.9)	1.6
Total operating revenues	1,562.1	44.5	(42.9)	1,563.7
OPERATING EXPENSES				
Cost of gas sold	504.7	—	—	504.7
Cost of fuel & purchased power	235.0	—	—	235.0
Other operating	341.9	—	(42.7)	299.2
Depreciation & amortization	161.1	26.7	0.4	188.2
Taxes other than income taxes	58.0	1.5	0.1	59.6
Total operating expenses	1,300.7	28.2	(42.2)	1,286.7
OPERATING INCOME	261.4	16.3	(0.7)	277.0
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	—	114.6	(114.6)	—
Other – net	4.3	51.1	(50.0)	5.4
Total other income (expense)	4.3	165.7	(164.6)	5.4
Interest expense	75.2	56.9	(50.7)	81.4
INCOME BEFORE INCOME TAXES	190.5	125.1	(114.6)	201.0
Income taxes	75.9	1.2	—	77.1

NET INCOME	$114.6	$123.9	$(114.6)	$123.9

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Consolidating Balance Sheet as of December 31, 2012 (in millions):

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Assets				
Cash & cash equivalents	$12.5	$0.8	$—	$13.3
Accounts receivable - less reserves	81.8	—	—	81.8
Intercompany receivables	—	145.1	(145.1)	—
Accrued unbilled revenues	93.6	—	—	93.6
Inventories	114.0	—	—	114.0
Recoverable fuel & natural gas costs	25.3	—	—	25.3
Prepayments & other current assets	52.0	5.8	(5.5)	52.3
Total current assets	379.2	151.7	(150.6)	380.3
Utility Plant				