VECTREN UTILITY HOLDINGS INC
Form 10-K/A
June 18, 2003

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

FORM 10-K/A
Amendment No. 1

(Mark One)

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

For the fiscal year ended December 31, 2002

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	35-2104850
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

20 N.W. Fourth Street, Evansville, Indiana	47708
(Address of principal executive offices)	(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
7 1/4% Senior Notes, due 10/15/2031	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 Stock - Without Par	None

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 |X|. 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. |X|

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ___. No |X|.

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 28, 2002 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.

Class	Number of Shares	Date
Common Stock- Without Par Value	10	March 15, 2003

Documents Incorporated by Reference

Certain information in Vectren Corporation's Definitive Proxy Statement for the 2003 Annual Meeting of Stockholders, which was filed with the Securities and Exchange Commission pursuant to Regulation 14A, on March 27, 2003, is incorporated by reference in Part III of this Form 10-K.

Definitions

AFUDC: allowance for funds used during construction

APB: Accounting Principles Board

EITF: Emerging Issues Task Force

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

IDEM: Indiana Department of Environmental Management

IURC: Indiana Utility Regulatory Commission

MCF / BCF: millions / billions of cubic feet

MDth / MMDth: thousands /millions

MMBTU: millions of British thermal units

MW: megawatts

MWh / GWh: megawatt hours / millions of megawatt hours (gigawatt hour)

NOx: nitrogen oxide

OUCC: Indiana Office of the Utility Consumer Counselor

PUCO: Public Utilities Commission of Ohio

SFAS: Statement of Financial Accounting Standards

USEPA: United States Environmental Protection Agency

Throughput: combined gas sales and

of dekatherms	gas transportation volumes

Table of Contents

Item Number		Page Number
	Part I	
1	Business	1
2	Properties	6
3	Legal Proceedings	7.
4	Submission of Matters to Vote of Security Holders	7
	Part II	
5	Market for the Company's Common Equity and Related Stockholder Matters	8
6	Selected Financial Data	9
7	Management's Discussion and Analysis of Results of Operations and Financial Condition	10
7A	Qualitative and Quantitative Disclosures About. Market Risk	29
8	Financial Statements and Supplementary Data	31
9	Change in and Disagreements with Accountants on Accounting and Financial Disclosure	75
	Part III	
10	Directors and Executive Officers of the Registrant	75
11	Executive Compensation	76
12	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	78
13	Certain Relationships and Related Transactions	80
	Part IV	
14	Controls and Procedures	81
15	Exhibits, Financial Statement Schedules, and Reports on Form 8-K	81
	Signatures	84

Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports free of charge, including those of its wholly owned subsidiaries, through its website at www.vectren.com, or by request, directed to Investor Relations at the mailing address, phone number, or email address that follows:

Mailing Address:	Phone Number:	Investor Relations Contact:
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Explanatory Note

This Amendment No. 1 to Form 10-K filed on Form 10-K/A for the year ended December 31, 2002, is being filed to reflect a transfer of net assets to Vectren Utility Holdings, Inc. (the Company or VUHI) from Vectren Corporation (Vectren) effective on January 1, 2003. The transfer requires the retroactive restatement of VUHI's consolidated financial statements for all periods presented under accounting rules governing combinations of entities under common control. Accordingly the consolidated financial statements, included in Item 8 of Part II, have been retroactively restated to reflect the combined financial position and combined results of operations and cash flows for all periods presented, giving effect to the transfer as if the combination had occurred at the beginning of the earliest period presented. The effects of the transaction are more fully described in Note 3 to the consolidated financial statements of Item 8 of Part II. This amendment also clarifies various disclosures in the Results of Operations and Financial Condition sections of Item 7 of Part II and the Consolidated Statements of Cash Flows and Notes 2, 3, 6, 10, 11, and 17 to the consolidated financial statements of Item 8 of Part II. All other information contained herein is as of February 26, 2003, and does not reflect any events or changes in information that may have occurred subsequent to February 26, 2003. For a discussion of events and developments relating to periods subsequent to February 26, 2003, see the Company's reports filed with the Securities and Exchange Commission for such subsequent periods, including the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003.

PART I

ITEM 1. BUSINESS

Description of the Business

Vectren Utility Holdings, Inc. (VUHI or the Company), 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), formerly a wholly owned subsidiary of Indiana Energy, Inc. (Indiana Energy), Southern Indiana Gas and Electric Company (SIGECO), formerly a wholly owned subsidiary of SIGCORP, Inc. (SIGCORP), and the Ohio operations. VUHI also has assets that provide information technology and other services to the utilities.

Indiana Gas provides natural gas distribution and transportation services to a diversified customer base in 49 of Indiana's 92 counties. SIGECO provides electric generation, transmission, and distribution services to 8 counties in southwestern Indiana, including counties surrounding Evansville, and participates in the wholesale power market. SIGECO also provides natural gas distribution and transportation services to 10 counties in southwestern Indiana, including counties surrounding Evansville. The Ohio operations provide natural gas distribution and transportation services to 17 counties in west central Ohio, including counties surrounding Dayton.

Vectren is an energy and applied technology holding company headquartered in Evansville, Indiana. The Company was organized on June 10, 1999 solely for the purpose of effecting the merger of Indiana Energy and SIGCORP. On March 31, 2000, the merger of Indiana Energy with SIGCORP and into Vectren was consummated with a tax-free exchange of shares and has been accounted for as a pooling-of-interests in accordance with APB Opinion No. 16 "Business Combinations" (APB 16).

Both Vectren and VUHI are exempt from registration pursuant to Section 3(a)(1) and 3(c) of the Public Utility Holding Company Act of 1935.

Acquisition of the Gas Distribution Assets of The Dayton Power and Light Company

On October 31, 2000, the Company acquired the natural gas distribution assets of

The Dayton Power and Light Company for $471 million, including transaction costs. The acquisition has been accounted for as a purchase transaction in accordance with APB 16, and accordingly, the results of operations of the acquired assets are included in the Company's financial results since the date of acquisition.

The Company acquired the natural gas distribution assets as a tenancy in common through two separate wholly owned subsidiaries. Vectren Energy Delivery of Ohio, Inc. (VEDO) holds a 53% undivided ownership interest in the assets, and Indiana Gas holds a 47% undivided ownership interest. VEDO is the operator of the assets, and these operations are referred to as "the Ohio operations."

Narrative Description of the Business

The Company segregates its businesses into gas utility services, electric utility services and other operations. The Gas Utility Services segment includes the operations of Indiana Gas, the Ohio operations, and SIGECO's natural gas distribution business and provides natural gas distribution and transportation services to nearly two-thirds of Indiana and west central Ohio. The Electric Utility Services segment includes the operations of SIGECO's electric transmission and distribution services, which provides electricity primarily to southwestern Indiana, and SIGECO's power generating and power marketing operations. Other Operations provide information technology and other support services to those utility operations.

At December 31, 2002, the Company had $2.6 billion in total assets, with $1.5 billion (61%) attributed to the gas utility operations, $0.9 billion (33%) attributed to the electric utility operations, and $0.2 billion (6%) attributed to other operations. Net income for the year ended 2002 was $97.1 million with $38.9 million attributed to gas utility operations, $55.6 million attributed to electric utility operations, and $2.6 million to other operations. Net income, as restated, for the year ended 2001 was $44.8 million. The year ending December 31, 2001 included nonrecurring charges with an after tax impact of $15.9 million. Nonrecurring items net of tax in 2001 included $7.7 million of merger and integration costs, $9.3 million of restructuring costs, and a $1.1 million gain resulting from a cumulative effect of change in accounting principle.

For further information refer to Note 3 regarding the restatement of previously reported information, Note 14 regarding the segments' activities and assets, Note 15 regarding special charges in 2001 and 2000, and Note 12 regarding the cumulative effect of change in accounting principle included under Item 8 Financial Statements and Supplementary Data. Following is a more detailed description of the gas and electric utility operations. The Company's other operations are not significant.

Gas Utility Services

At December 31, 2002, the Company supplied natural gas service to 966,761 Indiana and Ohio customers, including 882,151 residential, 80,483 commercial, and 4,127 industrial and other customers. This represents customer base growth of 1.4% compared to 2001.

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, appliance manufacturing, polycarbonate resin (Lexan) and plastic products, gypsum products, electrical equipment, metal specialties, glass, steel finishing, pharmaceutical and nutritional products, gasoline and oil products, and coal mining. The largest Indiana communities served are Evansville, Muncie, Anderson, Lafayette, West Lafayette, Bloomington, Terre Haute, Marion, New Albany, Columbus, Jeffersonville, New Castle, and Richmond. The largest community served outside of Indiana is Dayton, Ohio.

Revenues

For the year ended December 31, 2002, natural gas revenues were approximately $909.0 million of which residential customers accounted for 67%, commercial 23%, and industrial and other 10%, respectively.

The Company receives gas revenues by selling gas directly to residential, commercial, and industrial customers at approved rates or by transporting gas through its pipelines at approved rates to commercial and industrial customers that have purchased gas directly from other producers, brokers, or marketers. Total volumes of gas provided to both sales and transportation customers (throughput) was 207,693 MDth for the year ended December 31, 2002. Transported gas represented 44% of total throughput. Rates for transporting gas provide for the same margins generally earned by selling gas under applicable sales tariffs.

The sale of gas is seasonal and strongly affected by variations in weather conditions. To mitigate seasonal demand, the Company owns and operates seven underground gas storage fields and six liquefied petroleum air-gas manufacturing plants. The Company also contracts with ProLiance and other parties to ensure availability of gas. Natural gas purchased from suppliers is injected into storage during periods of light demand which are typically periods of lower prices. The injected gas is then available to supplement contracted and manufactured volumes during periods of peak requirements. Approximately 909,500 MCF of gas per day can be withdrawn during peak demand periods from all sources and for all utilities.

Gas Purchases

In 2002, the Company purchased natural gas from multiple suppliers including ProLiance Energy, LLC (ProLiance). ProLiance is an unconsolidated, nonregulated, energy marketing affiliate of Vectren and Citizens Gas and Coke Utility. (See Note 5 in the Company's consolidated financial statements included in Item 8 Financial Statements and Supplementary Data regarding transactions with ProLiance). The Company purchased 120,764 MDth volumes of gas in 2002 at an average cost of $4.57 per Dth, of which 94% was purchased from ProLiance. The average cost of gas per Dth purchased for the last five years was; $4.57 in 2002; $5.83 in 2001; $5.60 in 2000; $3.58 in 1999; and $3.53 in 1998.

Regulatory and Environmental Matters

See Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition regarding the Company's regulated environment and issues involving manufactured gas plants.

Electric Utility Services

At December 31, 2002, the Company supplied electric service to 134,057 Indiana customers, including 116,979 residential, 16,881 commercial, and 197 industrial and other customers. This represents customer base growth of 0.6% compared to 2001. In addition, the Company is obligated to provide for firm power commitments to several municipalities and to maintain spinning reserve margin requirements under an agreement with the East Central Area Reliability Group.

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

Revenues

For the year ended December 31, 2002, retail and firm wholesale electricity sales totaled 6,187,132 MWh, resulting in revenues of approximately $305.3 million. Residential customers accounted for 35% of 2002 revenues; commercial 26%; industrial and municipalities 37%; and other 2%. In addition, the Company sold 10,711,614 MWh through non-firm wholesale contracts in 2002 generating revenue of $302.8 million.

Generating Capacity

Installed generating capacity as of December 31, 2002 was rated at 1,351 MW. Coal-fired generating units provide 1,056 MW of capacity, and gas or oil-fired turbines used for peaking or emergency conditions provide 295 MW. New peaking capacity of 80 MW fueled by natural gas was added during 2002 and was available for the summer peaking season.

In addition to its generating capacity, throughout 2002 the Company had 82MW available under firm contracts and 95 MW available under interruptible contracts. On January 1, 2003, a 50 MW firm contract expired and was no longer required and therefore not renewed.

The Company has interconnections with Louisville Gas and Electric Company, Cinergy Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc., Big Rivers Electric Corporation, Wabash Valley Power Association, and the City of Jasper, Indiana, providing the historic ability to simultaneously interchange approximately 500 MW. However, the ability of the Company to effectively utilize the electric transmission grid in order to achieve import/export capability may be impacted because the Company, as a member of the Midwest Independent System Operator (MISO), has turned over operational control over the interchange facilities and its own transmission assets like many other Midwestern electric utilities to the MISO. See Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition regarding the Company's participation in MISO.

Total load for each of the years 1998 through 2002 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	8/5/02	7/31/01	8/17/00	7/6/99	7/21/98
Total load at peak (1)	1,258	1,234	1,212	1,255	1,154
Generating capability	1,351	1,271	1,256	1,256	1,256
Firm purchase supply	82	82	75	-	-
Interruptible contracts	95	95	95	95	85
Total power supply capacity	1,528	1,448	1,426	1,351	1,341
Reserve margin at peak	21%	17%	18%	8%	16%

(1) The total load at peak is increased 25MW in 2002, 2001, 1999, and 1998 from the total load actually experienced. The additional 25 MW represents load that would have been incurred if summer cycler programs had not been activated. The 25 MW is also included in the interruptible contract portion of the Company's total power supply capacity. On the date of peak in 2000, summer cycler programs were not activated.

The winter peak load of the 2001-2002 season of approximately 854 MW occurred on March 4, 2002 and was 8% lower than the previous winter peak load of approximately 925 MW which occurred on December 19, 2000.

The Company maintains a 1.5% interest in the Ohio Valley Electric Corporation

(OVEC). The OVEC is comprised of 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 are entitled to 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. Because of this decreased demand, the Company's 1.5% interest in the OVEC makes available approximately 32 MW of capacity, in addition to its generating capacity, for use in other operations.

Fuel Costs and Purchased Power

Electric generation for 2002 was fueled by coal (97.5%) and natural gas (2.5%). Oil was used only for testing of gas/oil-fired peaking units.

There are substantial coal reserves in the southern Indiana area, and coal for coal-fired generating stations has been supplied from operators of nearby Indiana coal mines including those owned by Vectren Fuels, Inc., a wholly owned subsidiary of Vectren. Approximately 3.1 million tons of coal was purchased for generating electricity during 2002. Of this amount, Vectren Fuels, Inc. supplied 2.7 million tons from its mines and third party purchases. The average cost of coal consumed in generating electrical energy for the years 1998 through 2002 follows:

	Year				
Avg. Cost Per	2002	2001	2000	1999	1998
Ton	$ 23.50	$ 22.48	$ 22.49	$ 21.88	$ 21.34
MWh	11.00	10.53	10.39	10.13	9.97

The Company will also purchase power as needed from the wholesale market to supplement its generation capabilities in periods of peak demand; however, the majority of power purchased through the wholesale market is used to optimize and hedge the Company's sales to non-firm wholesale customers. Volumes purchased in 2002 totaled 10,362,196 MWh.

Regulatory and Environmental Matters

See Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition regarding the Company's regulated environment, and a discussion of the Company's Clean Air Act Compliance Plan, and the USEPA's lawsuit against SIGECO for alleged violations of the Clean Air Act.

Competition

See Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition regarding competition within the public utility industry for the Company's regulated Indiana and Ohio operations.

Personnel

As of December 31, 2002, the Company and its consolidated subsidiaries had 1,581 employees, of which 896 are subject to collective bargaining arrangements.

In August 2001, the Company signed a new four-year labor agreement, ending in September 2005 with Local 135 of the Teamsters, Chauffeurs, Warehousemen and Helpers. The new agreement provides for annual wage increases of 3.25%, a new 401(k) savings plan and improvements in the areas of health insurance and pension benefits.

Concurrent with the Company's purchase of the Ohio operations, VEDO and Local Union 175, Utility Workers Union of America approved a labor agreement effective

November 2000, through October 2005. The agreement provides a 3.25% wage increase each year, and the other terms and conditions are substantially the same as the agreement reached between the Utility Workers Union and Dayton Power and Light Company in August of 2000.

In July 2000, SIGECO signed a new four-year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 2004. The new agreement provides a 3% wage increase for each year in addition to improvements in health care coverage, retirement benefits and incentive pay.

ITEM 2. PROPERTIES

Gas Utility Services

Indiana Gas owns and operates four gas storage fields located in Indiana covering 58,489 acres of land with an estimated ready delivery from storage capability of 4.2 BCF of gas with delivery capabilities of 119,160 MCF per day. Indiana Gas also owns and operates three liquefied petroleum (propane) air-gas manufacturing plants located in Indiana with the ability to store 1.5 million gallons of propane and manufacture for delivery 31,000 MCF of manufactured gas per day. In addition to its owned storage and manufacturing and daily delivery capabilities, Indiana Gas contracts for a maximum of 17.2 BCF of gas availability across various pipelines with a delivery capability of 283,298 MCF per day. Indiana Gas' gas delivery system includes 11,590 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 underground gas storage fields located in Indiana covering 6,070 acres of land with an estimated ready delivery from storage capability of 8.7 BCF of gas with delivery capabilities of 124,748 MCF per day. In addition to its owned storage and daily delivery capabilities, SIGECO contracts for a maximum of 0.5 BCF of gas availability across various pipelines with a delivery capability of 18,753 MCF per day. SIGECO's gas delivery system includes 2,996 miles of distribution and transmission mains, all of which are located in Indiana.

The Ohio operations owns and operates three liquefied petroleum (propane) air-gas manufacturing plants and one cavern for propane storage, all of which are located in Ohio. The plants and cavern can store 3.7 million gallons of propane, and the plants can manufacture for delivery 51,047 MCF of manufactured gas per day. In addition to its owned storage and manufacturing and daily delivery capabilities, the Ohio operations contracts for a maximum of 13.2 BCF of gas availability across various pipelines with a delivery capability of 281,491 MCF per day. The Ohio operations' gas delivery system includes 5,176 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, 2002, was rated at 1,351 MW. SIGECO's coal-fired generating facilities are: the Brown Station with 500 MW of capacity, located in Posey County approximately eight miles east of Mt. Vernon, Indiana; the Culley Station with 406 MW of 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: the 80 MW Brown 3 Gas Turbine 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, 50MW and Broadway Avenue Unit 2, 65MW); two Northeast Gas Turbines located northeast of Evansville in Vanderburgh County, Indiana with a combined capacity of 20 MW; and a new 80MW turbine also located at the Brown station (Brown Unit 4) placed into service in 2002. The Brown Unit 3 and Broadway Avenue Unit 2 turbines are also equipped to burn oil. Total capacity of SIGECO's six gas turbines is 295 MW, and they are generally used only for reserve, peaking, or emergency purposes due to the higher per unit cost of generation.

SIGECO's transmission system consists of 829 circuit miles of 138,000 and 69,000 volt lines. The transmission system also includes 27 substations with an installed capacity of 4,221.2 megavolt amperes (Mva). The electric distribution system includes 3,212 pole miles of lower voltage overhead lines and 275 trench miles of conduit containing 1,541 miles of underground distribution cable. The distribution system also includes 95 distribution substations with an installed capacity of 1,939.5 Mva and 51,030 distribution transformers with an installed capacity of 2,352.3 Mva.

SIGECO owns utility property outside of Indiana approximating eight miles of 138,000 volt electric transmission line which is located in Kentucky and which interconnects with Louisville Gas and Electric Company's transmission system at Cloverport, 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 arising in the normal course of business. In the opinion of management, there are no legal proceedings pending against the Company that are likely to have a material adverse effect on its financial position or results of operations. See Note 10 of its consolidated financial statements included in Item 8 Financial Statements and Supplementary Data regarding the Clean Air Act and related legal proceedings. Legal proceedings involving transactions with ProLiance were substantially resolved during 2002. See Note 5 for a discussion of regulatory matters related to ProLiance.

ITEM 4. Submission of Matters to Vote of Security Holders

No matters were submitted during the fourth quarter to a vote of security holders.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Common Stock

Market Price

All of the outstanding shares of VUHI's common stock are owned by Vectren.

VUHI's common stock is not traded.

There are no outstanding options or warrants to purchase VUHI's common equity or securities convertible into VUHI's common equity. Additionally, VUHI has no plans to publicly offer any of its common equity.

Dividends Paid to Parent

During 2002, VUHI paid dividends to its parent company of $17.9 million in each of the first three quarters and $18.0 million in the fourth quarter.

During 2001, VUHI paid dividends to its parent company of $16.5 million, $14.3 million, $15.9 million, and $18.2 million in the first, second, third, and fourth quarters, respectively.

On January 22, 2003, the board of directors declared a dividend $18.2 million, payable to Vectren on March 3, 2003.

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.

Debt Security

The Company's 7 1/4% Senior Notes, due October 15, 2031, trade on the New York Stock Exchange under the symbol "AVU." The high and low sales prices for the Company's publicly traded debt security since issuance in October 2001 as reported on the New York Stock Exchange are shown in the following table for the periods indicated.

	Price Range	
2002	High	Low
First Quarter	$ 25.60	$ 24.50
Second Quarter	25.40	24.50
Third Quarter	25.95	24.80
Fourth Quarter	26.08	25.15
2001		
Fourth Quarter	$ 25.50	$ 24.95

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/A. The financial information as of and for the years ended December 31, 2001 and 2000 has been restated due to errors in previously reported financial statements. Common shareholder's equity as of January 1, 2000 also reflects adjustments for the restatement related to years prior to 2000. Effective January 1, 2003, Vectren transferred certain information technology systems and related assets and buildings from other entities within its consolidated group to VUHI. These assets primarily support the operations of VUHI's subsidiaries. The transfer required retroactive restatement of VUHI's consolidated financial statements for all periods presented under accounting rules governing combinations of entities under common control. The following selected financial data gives effect to the transfer. See Note 3 to the consolidated financial statements included under Item 8 Financial Statements and Supplementary Data for further information on the restatement and the asset transfer.

	Year Ended December 31				
In millions	2002	2001 (1)	2000(2,3)	1999	1998
		(As Restated)			
Operating Data:					
Operating revenues	$1,517.4	$1,401.0	$1,155.1	$ 807.1	$ 785.1
Operating income	$ 207.7	$ 131.4	$ 136.1	$ 109.0	$ 104.0
Income before cumulative effect of change in accounting principle	$ 97.1	$ 43.7	$ 55.9	$ 75.4	$ 69.3
Net income	$ 97.1	$ 44.8	$ 55.9	$ 75.4	$ 69.3
Balance Sheet Data:					
Total assets	$2,570.4	$2,489.3	$2,509.0	$1,667.7	$1,612.5
Redeemable preferred stock	$ 0.3	$ 0.5	$ 8.1	$ 8.2	$ 8.3
Long-term debt-net of current maturities & debt subject to tender	$ 841.2	$ 900.9	$ 572.6	$ 450.1	$ 351.7
Common shareholder's equity	$ 768.6	$ 738.9	$ 624.3	$ 627.0	$ 609.9

(1) Merger and integration related costs incurred for the year ended December 31, 2001 totaled $2.8 million. These costs relate primarily to transaction costs, severance and other merger and acquisition integration activities. As a result of merger integration activities, management retired certain information systems in 2001. Accordingly, the useful lives of these assets were shortened in 2000 to reflect this decision, resulting in additional depreciation expense of $9.6 million for the year ended December 31, 2001. In total, merger and integration related costs incurred for the year ended December 31, 2001 were $12.4 million ($7.7 million after tax).

The Company incurred restructuring charges of $15.0 million, ($9.3 million after tax) relating to employee severance, related benefits and other employee related costs, lease termination fees related to duplicate facilities, and consulting and other fees.

(2) Merger and integration related costs incurred for the year ended December 31, 2000 totaled $32.7 million. These costs relate primarily to transaction costs, severance and other merger and acquisition integration activities. As a result of merger integration activities, management identified certain information systems to be retired in 2001. Accordingly, the useful lives of these assets were shortened to reflect this decision, resulting in additional depreciation expense of $11.4 million for the year ended December 31, 2000. In total, merger and integration related costs incurred for the year ended December 31, 2000 were $44.1 million ($31.6 million after tax).

(3) Reflects two months of results of the Ohio operations.

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and notes thereto. As discussed in Note 3 in the consolidated financial statements, subsequent to the issuance of the

Company's 2001 financial statements, the Company's management determined that previously issued financial statements should be restated. As a result, the Company has restated its 2001 and 2000 financial statements and has increased reported retained earnings as of January 1, 2000 by $1.7 million. The restatement had the effect of decreasing net income for 2001 by approximately $10.6 million and increasing net income for 2000 by approximately $100,000. Note 3 to the consolidated financial statements includes a summary of the significant effects of the restatement. The effect of the restatement on quarterly results, including previously reported 2002 quarterly information, is discussed in Note 18.

Effective January 1, 2003, Vectren transferred certain information technology systems and related assets and buildings from other entities within its consolidated group to VUHI. These assets primarily support the operations of VUHI's subsidiaries. The transfer required retroactive restatement of VUHI's consolidated financial statements for all periods presented under accounting rules governing combinations of entities under common control. The asset transfer increased previously reported net income for 2001 by $4.7 million and for 2000 by $3.4 million.

The following discussion and analysis gives effect to the restatement.

Consolidated Results of Operations

In 2002, consolidated net income was $97.1 million, an increase of $52.3 million when compared to 2001, as restated. The year ended December 31, 2001 included nonrecurring merger, integration, and restructuring costs and other nonrecurring items totaling $15.9 million after tax. In addition to the nonrecurring 2001 items, the increase reflects improved margins and lower operating costs. These resulted from favorable weather and a return to lower gas prices and the related reduction in costs incurred in 2001. Weather increased utility earnings by an estimated $11 million.

In 2001, consolidated net income of $44.8 million decreased $11.1 million when compared to 2000. The year ended December 31, 2000 included nonrecurring merger and integration costs totaling $31.6 million after tax. The decrease reflects lower earnings resulting from extraordinarily high gas costs early in 2001 that unfavorably impacted margins and operating costs including uncollectible accounts expense, interest, and excise taxes; heating weather that was 9% warmer than the prior year; and a weakened national economy.

Restatement of Previously Reported Results

The Company identified adjustments that, in the aggregate, reduced previously reported 2001 earnings by approximately $10.6 million after tax and other adjustments, as described below, related to 2000 and prior periods. Adjustments were also made to previously reported 2002 quarterly results. In addition to adjustments affecting previously reported net income, other reclassifications were made to the previously reported 2001 and 2000 results to conform with the 2002 presentation.

Previously Reported 2001 and 2000 Net Income Adjustments

The Company determined that $11.6 million ($7.2 million after tax) of gas costs were improperly recorded as recoverable gas costs due from customers. The error related primarily to the accounting for natural gas inventory and resulted in an overstatement of 2001 earnings.

The Company also identified an accounting error related to certain employee benefit and other related costs that are routinely accumulated on the balance sheet and systematically cleared to operating expense and capital projects.

Because of inadequate loading rates, these costs were not fully cleared to operating expense and capital projects in 2001. As a result, 2001 earnings were overstated by $5.6 million ($3.5 million after tax).

The accounting for certain wholesale power marketing contracts was modified to comply with SFAS 133, which became effective on January 1, 2001. The cumulative effect at adoption was decreased by $2.8 million after tax. This change was offset substantially by an increase in electric margins throughout 2001.

The Company identified reconciliation errors and other errors related to the recording of estimates that were not significant, either individually or in the aggregate. As a result of these additional items, 2001 earnings were reduced by $2.2 million ($1.4 million after tax). Originally reflected in 2001, the correction of the year 2000 overstatement of electric revenue totaling $2.4 million ($1.5 million after tax), now reflected in 2000 as discussed below, significantly offset these additional items.

The Company also determined that certain billings and collections had been improperly recorded in 2000, resulting in an understatement of gas revenue by $1.8 million ($1.1 million after tax) and an overstatement of electric revenue by $2.4 million ($1.5 million after tax). Other errors were identified that increased 2000 earnings by $0.8 million ($0.5 million after tax). The impact of the restatement of results for the year ended 2000 is an increase to net income of approximately $100,000.

Previously Reported 2002 Quarterly Net Income Adjustments

As previously reported, in the second quarter of 2002 the Company recorded $5.2 million ($3.2 million after tax) of carrying costs for DSM programs pursuant to existing IURC orders and based on an improved regulatory environment. During the audit of the three years ended December 31, 2002, management determined that the accrual of such carrying costs was more appropriate in periods prior to 2000 when DSM program expenditures were made. Therefore, such carrying costs originally reflected in 2002 quarterly results were reversed and reflected in common shareholder's equity as of January 1, 2000. In addition, the Company identified other adjustments that were not significant, either individually or in the aggregate that increased previously reported 2002 quarterly pre-tax and after tax earnings by approximately $1.8 million and $1.1 million after tax, respectively. The cumulative impact from of these adjustments reduced previously reported earnings for the nine months ended September 30, 2002 by approximately $2.1 million.

Beginning Retained Earnings Adjustments

In addition to the adjustment of DSM costs above, the Company identified other errors that were not significant, either individually or in the aggregate that relate to years prior to 2000. As a result of these additional items, beginning common shareholders' equity was reduced by $1.5 million. Accordingly, retained earnings as of January 1, 2000 reflects a cumulative net increase of $1.7 million.

Other Balance Sheet Adjustments

Certain reclassifications were made to reflect separate Company prepaid and accrued taxes that result in the consolidated tax position. This adjustment added approximately $26.6 million to receivables due from other Vectren companies and prepaid and other current assets with a corresponding increase in payables due to other Vectren companies, accrued liabilities, and deferred taxes as of December 31, 2001. The Company also reclassified all previously recorded goodwill not included in rates to goodwill on the balance sheet. This adjustment resulted in a $5.9 million decrease in other assets, a $3.0 million decrease in prepayments and other current assets and an $8.9 million increase in goodwill.

Transfer of Assets to VUHI

Effective January 1, 2003, Vectren transferred certain information technology systems and related assets and buildings from other entities within its consolidated group to VUHI. These assets primarily support the operations of VUHI's subsidiaries. The transfer requires retroactive restatement of VUHI's consolidated financial statements for all periods presented under accounting rules governing combinations of entities under common control. The asset transfer increased previously reported operating income and net income by $8.1 million and $4.7 million, respectively, in 2001 and by $6.2 million and $3.4 million, respectively, in 2000. As a result of the transfer, 2001 total assets (primarily non-utility property), liabilities (primarily intercompany payables and borrowings), and equity transferred increased $86.7 million, $51.9 million, and $34.8 million, respectively. The years ended December 31, 2001 and 2000 have been restated for this asset transfer, and the year ended December 31, 2002 reflects that asset transfer.

The Company has restated its financial statements to give effect to the matters discussed above. A summary of the significant effects of the restatement on previously reported financial position and results of operations is included in Note 3 to the consolidated financial statements. The effects of the restatement on 2001 quarterly results and on 2002 previously reported quarterly information, is discussed in Note 18. The consolidated financial statements are included under Item 8 Financial Statements and Supplementary Data.

Nonrecurring Items in 2001 and 2000

Merger & Integration Costs

Merger and integration costs incurred for the years ended December 31, 2001 and 2000 were $2.8 million and $32.7 million, respectively. Merger and integration activities resulting from the 2000 merger were completed in 2001.

Since March 31, 2000, $35.5 million has been expensed associated with merger and integration activities. Accruals were established at March 31, 2000 totaling $19.3 million. Of this amount, $5.5 million related to employee and executive severance costs, $11.7 million related to transaction costs and regulatory filing fees incurred prior to the closing of the merger, and the remaining $2.1 million related to employee relocations that occurred prior to or coincident with the merger closing. The remaining $16.2 million was expensed through December 31, 2001 ($13.4 million in 2000 and $2.8 million in 2001) for accounting fees resulting from merger related filing requirements, consulting fees related to integration activities such as organization structure, employee travel between company locations as part of integration activities, internal labor of employees assigned to integration teams, investor relations communications activities, and certain benefit costs.

The integration activities experienced by the Company included such things as information system consolidation, process review and definition, organization design and consolidation, and knowledge sharing.

As a result of merger integration activities, management retired certain information systems in 2001. Accordingly, the useful lives of these assets were shortened in 2000 to reflect this decision, resulting in additional depreciation expense of $9.6 million for the year ended December 31, 2001 and $11.4 million for the year ended December 31, 2000.

In total, for the year ended December 31, 2001, merger and integration costs totaled $12.4 million ($7.7 million after tax) compared to $44.1 million ($31.6 million after tax) in 2000.

Restructuring Costs

As part of continued cost saving efforts, in June 2001, the Company's management and board of directors approved a plan to restructure, primarily, its regulated operations. The restructuring plan included the elimination of certain administrative and supervisory positions in its utility operations and corporate office. Charges of $10.8 million were expensed in June 2001 as a direct result of the restructuring plan. Additional charges of $4.2 million were incurred during the remainder of 2001 primarily for consulting fees, employee relocation, and duplicate facilities costs. In total, the Company incurred restructuring charges of $15.0 million, ($9.3 million after tax) in 2001. These charges were comprised of $7.6 million for employee severance, related benefits and other employee related costs, $4.0 million for lease termination fees related to duplicate facilities and other facility costs, and $3.4 million for consulting and other fees incurred through December 31, 2001. The restructuring program was completed during 2001, except for the departure of certain employees impacted by the restructuring which occurred during 2002 and the final settlement of the lease obligation which has yet to occur. (See Note 15 for further information on restructuring costs.)

Cumulative Effect of Change in Accounting Principle

Resulting from the adoption of SFAS 133, certain contracts in the power marketing operations that are periodically settled net were required to be recorded at market value. Previously, the Company accounted for these contracts on settlement. The cumulative impact of the adoption of SFAS 133 resulting from marking these contracts to market on January 1, 2001 was an earnings gain of approximately $1.8 million ($1.1 million after tax) recorded as a cumulative effect of change in accounting principle in the Consolidated Statements of Income.

Significant Fluctuations

Utility Margin

Gas Utility Margin

Gas Utility margin for the year ended December 31, 2002 of $337.2 million increased $26.5 million, or 9%. The increase is primarily due to weather 7% cooler for the year and 31% cooler in the fourth quarter. Rate recovery of excise taxes in Ohio effective July 1, 2001, an increase in the Percent of Income Payment Plan rider affecting Ohio customers, decreased gas costs, and customer growth of over 1% also contributed. It is estimated that of the increase in gas utility margin weather contributed $10 million, various rate recovery riders in Ohio contributed $7 million, and other items, including the impact of lower gas costs and customer growth, contributed $9 million. The effects of cooler weather resulted in an overall 4% increase in total throughput to 207.7 MMDth in 2002 from 199.3 MMDth in 2001. Total throughput in 2000 was 181.2 MMDth, which includes two months of throughput from the Ohio operations.

Gas Utility margin for the year ended December 31, 2001 of $310.7 million increased $42.8 million, compared to 2000. Excluding the Ohio operations, gas margin decreased by $15.7 million, or 6%. The primary factors contributing to this decrease were weather that was 9% warmer than the prior year and the unfavorable impact resulting from extraordinarily high gas costs early in 2001, coupled with the effects of a weakened economy. These decreases were offset somewhat by customer growth of nearly 1% compared to 2000.

Cost of gas sold was $571.8 million in 2002, $708.9 million in 2001, and $552.5 million in 2000. Cost of gas sold decreased $137.1 million, or 19%, during 2002 compared to 2001, primarily due to a return to lower gas prices somewhat offset by an increase in retail volumes sold. Of the change in 2001 compared to 2000, the Ohio operations contributed $179.4 million of the increase. Excluding the Ohio operations, cost of gas sold decreased $23.0 million, or 4%, in 2001. The decrease is primarily due to lower volumes sold due to the warmer weather and a weakened economy, offset by an increase in gas prices. The total average cost per dekatherm of gas purchased was $4.57 in 2002, $5.83 in 2001, and $5.60 in 2000. The price changes are due primarily to changing commodity costs in the marketplace.

Electric Utility Margin

Electric Utility margin by customer type and non-firm wholesale margin separated between realized margin and mark-to-market gains and losses follows:

	Year ended December 31,		
In millions	2002	2001	2000
Retail & firm wholesale	$ 215.3	$ 200.0	$ 201.2
Non-firm wholesale	14.9	19.9	21.1
Total margin	$ 230.2	$ 219.9	$ 222.3
Non-firm wholesale margin:			
Realized margin	$ 18.5	$ 18.4	$ 21.1
Mark-to-market gains (losses)	(3.6)	1.5	-

Electric Utility margin for the year ended December 31, 2002 increased $10.3 million, or 5%, when compared to 2001. The increases result primarily from the effect on retail sales of cooling weather considerably warmer than the prior year. Weather in 2002 was 27% warmer when compared to 2001 and 23% warmer than normal. In addition to weather, 2002 was positively affected by increased industrial and firm wholesale volumes and a cash return on NOx compliance expenditures as the expenditures are made pursuant to a rate recovery rider approved by the IURC in August 2001. As a result of warmer weather and increased volumes sold, retail and firm wholesale volumes sold increased from 5.8 GWh in 2001 to 6.2 GWh in 2002. Volumes sold in 2000 were 5.9 GWh. It is estimated that of the increase in electric utility margin weather contributed $7 million, and the increased industrial and firm wholesale volumes and NOx recovery rider contributed $8 million. The current year increase in margin from retail sales was partially offset by $5 million in lower margins earned in the wholesale energy market.

Electric Utility margin for the year ended December 31, 2001 decreased $2.4 million, or 1%, compared to 2000 primarily from decreased sales to firm wholesale customers and decreased margin on non-firm wholesale activity. The decreases were partially offset by a 3% increase in residential and commercial sales due to cooling weather 7% warmer than the prior year and a 3% increase in the number of residential and commercial customers.

Periodically, generation capacity is in excess of that needed to serve retail and firm wholesale customers. The Company markets this unutilized capacity to optimize the return on its owned generation assets. The contracts entered into are primarily short-term purchase and sale transactions that expose the Company to limited market risk. While volumes both sold and purchased in the wholesale market have increased during 2002, margins softened as a result of reduced price volatility. As a result of increased activity offset by reduced price volatility, margin from power marketing activities decreased $5.0 million during

2002 and $1.2 million during 2001. In 2002, volumes sold into the wholesale market were 10.7 GWh compared to 3.4 GWh in 2001 and 1.6 GWh in 2000. Volumes purchased from the wholesale market, some of which were utilized to serve retail and firm wholesale customers, were 10.3 GWh in 2002 compared to 2.9 GWh in 2001 and 1.2 GWh in 2000.

Operating Expenses

Other Operating
Other operating expenses decreased $13.5 million for the year ended December 31, 2002 when compared to 2001. The decrease results primarily from a return to lower gas prices and the related reduction in costs incurred in 2001. Specific expenses affected by increased gas costs in 2001 were uncollectible accounts expense of $3.4 million and contributions to low income heating assistance programs of $2.0 million. Insurance recovery in 2002 of $2.8 million in certain maintenance costs incurred in 2001 also contributed to the decrease.

Excluding $31.2 million in additional expenses related to the Ohio operations, other operating expenses for the year ended December 31, 2001 decreased $0.3 million compared to 2000. The 2001 decrease results primarily from prior merger synergies, offset by higher expenses resulting from increased gas costs.

Depreciation & Amortization
Depreciation and amortization decreased $7.2 million for the year ended December 31, 2002 when compared to 2001. The decrease results from a $9.6 million decrease related to assets which had useful lives shortened as a result of the merger and the discontinuance of goodwill amortization as required by SFAS 142, which approximated $4.9 million in 2001.These decreases were offset somewhat by depreciation of utility plant and non-utility property additions.
Depreciation and amortization increased $13.3 million in 2001 when compared to 2000. The increase is due to the inclusion of the Ohio operations and depreciation of normal utility plant additions at Indiana Gas and SIGECO. For the year ended December 31, 2001, the increase in utility depreciation and amortization related to the Ohio operations was $12.9 million, including amortization of goodwill of $4.9 million.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $0.9 million in 2002 compared to 2001 as a result of lower revenues subject to gross receipts tax and increased $15.1 million in 2001 compared to 2000. The year ended December 31, 2001 includes $15.3 million of additional expense related to the Ohio operations, primarily state excise tax.

Other Income - Net

Other- net
Other income, net increased $1.5 million in 2002 when compared to 2001 and amounts in 2001 were comparable to 2000. The increase in 2002 is primarily attributable to gains recognized from the sale of excess emission allowances.

Equity in Earnings of Unconsolidated Affiliates
Equity in earnings of unconsolidated affiliates decreased $1.3 million in 2002 and $0.5 million in 2001 principally due to increased losses and increased ownership in a company that manufactures autoclaved aerated concrete products from fly ash.

Interest Expense

Interest expense decreased $1.6 million in 2002 compared to 2001. The decrease is attributable to lower average interest rates on adjustable rate debt.

Interest expense increased $24.3 million during the 2001 compared to 2000. The increase is due primarily to interest related to financing the acquisition of the Ohio operations and increased working capital requirements resulting from higher natural gas prices.

Income Tax

Federal and state income taxes increased $25.5 million for the year ended December 31, 2002 when compared to 2001. The increase results principally from higher pre-tax earnings. The effective tax rate increased in 2002 due to amortization of investment tax credits and higher pre-tax income.

Federal and state income taxes decreased $15.8 million in 2001 when compared to 2000. The 2001 decrease is due to lower pre-tax earnings. The effective tax rate decreased in 2001 due primarily to the nondeductibility of certain merger and integration costs incurred in 2000 and amortization of investment tax credits.

Competition

The utility industry has been undergoing dramatic structural change for several years, resulting in increasing competitive pressures faced by electric and gas utility companies. Increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and gas sales. Currently, several states, including Ohio, have passed legislation allowing electricity customers to choose their electricity supplier in a competitive electricity market and several other states are considering 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. Indiana has not adopted any regulation requiring gas choice; however, the Company operates under approved tariffs permitting large volume customers to choose their commodity supplier.

Other Operating Matters

Midwest Independent System Operator

The FERC approved the Midwest Independent System Operator (MISO) as the nation's first regional transmission organization. Regional transmission organizations place public utility transmission facilities in a region under common control. The FERC has made regional transmission organizations a top priority to boost competition and to provide more reliable power at lower rates. The Carmel, Indiana, based MISO began some operations in December 2001 with control of 73,000 miles of transmission lines carrying up to 81,000 MW. More than 20 states are included in the MISO from the Midwest and Plains states, to Texas, Arkansas, and part of the Southeast. In December 2001, the IURC approved the Company's request for authority to transfer operational control over its electric transmission facilities to the MISO. That transfer occurred on February 1, 2002.

Issues pertaining to certain of MISO's tariff charges for its services remain to be determined by the FERC. Given the outstanding tariff issues, as well as the potential for additional growth in MISO participation, the Company is unable to determine the future impact MISO participation may have on its operations. Pursuant to an order from the IURC, certain MISO costs are deferred for future recovery.

As a result of MISO's operational control over much of the Midwestern electric transmission grid, including SIGECO's transmission facilities, SIGECO's continued ability to import power, when necessary, may be impacted. Given the nature of MISO's policies regarding use of transmission facilities, as well as ongoing FERC initiatives, it is difficult to predict the impact on operational reliability. The potential need to expend capital for improvements to the transmission system, both to SIGECO's facilities as well as to those facilities of adjacent utilities, over the next several years will become more predictable as MISO completes studies related to regional transmission planning and improvements. Such expenditures may be significant.

Environmental Matters

The Company is subject to federal, state, and local regulations with respect to environmental matters, principally air, solid waste, and water quality. Pursuant to environmental regulations, the Company is required to obtain operating permits for the electric generating plants that it owns or operates and construction permits for any new plants it might propose to build. Regulations concerning air quality establish standards with respect to both ambient air quality and emissions from electric generating facilities, including particulate matter, sulfur dioxide (SO_2), and nitrogen oxides (NO_x). Regulations concerning water quality establish standards relating to intake and discharge of water from electric generating facilities, including water used for cooling purposes in electric generating facilities. Because of the scope and complexity of these regulations, the Company is unable to predict the ultimate effect of such regulations on its future operations, nor is it possible to predict what other regulations may be adopted in the future. The Company intends to comply with all applicable governmental regulations, but will contest any regulation it deems to be unreasonable or impossible to comply with.

Clean Air Act

NOx SIP Call Matter

The Clean Air Act (the Act) requires each state to adopt a State Implementation Plan (SIP) to attain and maintain National Ambient Air Quality Standards (NAAQS) for a number of pollutants, including ozone. If the USEPA finds a state's SIP inadequate to achieve the NAAQS, the USEPA can call upon the state to revise its SIP (a SIP Call).

In October 1998, the USEPA issued a final rule "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone," (63 Fed. Reg. 57355). This ruling found that the SIP's of certain states, including Indiana, were substantially inadequate since they allowed for NOx emissions in amounts that contributed to non-attainment with the ozone NAAQS in downwind states. The USEPA required each state to revise its SIP to provide for further NOx emission reductions. The NOx emissions budget, as stipulated in the USEPA's final ruling, requires a 31% reduction in total NOx emissions from Indiana.

In June 2001, the Indiana Air Pollution Control Board adopted final rules to achieve the NOx emission reductions required by the NOx SIP Call. Indiana's SIP requires the Company to lower its system-wide NOx emissions to .14 lbs./MMBTU by May 31, 2004 (the compliance date). This is a 65% reduction from emission levels existing in 1999 and 1998.

The Company has initiated steps toward compliance with the revised regulations. These steps include installing Selective Catalytic Reduction (SCR) systems at Culley Generating Station Unit 3 (Culley), Warrick Generating Station Unit 4, and A.B. Brown Generating Station Units 1 and 2. SCR systems reduce flue gas NOx emissions to atmospheric nitrogen and water using ammonia in a chemical reaction. This technology is known to be the most effective method of reducing NOx emissions where high removal efficiencies are required.

On August 28, 2001, the IURC issued an order that (1) approved the Company's proposed project to achieve environmental compliance by investing in clean coal technology, (2) approved the Company's initial cost estimate of $198 million for the construction, subject to periodic review of the actual costs incurred, and (3) approved a mechanism whereby, prior to an electric base rate case, the

Company may recover through a rider that is updated every six months a return on its capital costs for the project, at its overall cost of capital, including a return on equity. The first rider adjustment for ongoing cost recovery was approved by the IURC on February 6, 2002. Based on the level of system-wide emissions reductions required and the control technology utilized to achieve the reductions, the current estimated clean coal technology construction cost ranges from $240 million to $250 million and is expected to be expended during the 2001-2006 period. Through December 31, 2002, $70.0 million has been expended.

On June 5, 2002, the Company filed a new proceeding to update the NOx project cost and to obtain approval of a second rider authorizing ongoing recovery of depreciation and operating costs related to the clean coal technology. After the equipment is installed and operational, related annual operating expenses, including depreciation expense, are estimated to be between $24 million and $27 million. Such expenses would commence in 2004 when the technology becomes operational. On January 3, 2003, the IURC approved a settlement that authorizes total capital cost investment for this project up to $244 million (excluding AFUDC) and recovery on those capital costs, as well as the recovery of future operating costs, including depreciation and purchased emission allowances, through a rider mechanism. The settlement establishes a fixed return of 8 percent on the capital investment, which approximates the return authorized in the Company's last electric rate case in 1995.

The Company expects to achieve timely compliance as a result of the project. Construction of the first SCR at Culley is nearing completion on schedule, and installation of SCR technology as planned is expected to reduce the Company's overall NOx emissions to levels compliant with Indiana's NOx emissions budget allotted by the USEPA. Therefore, the Company has recorded no accrual for potential penalties that may result from noncompliance.

Culley Generating Station Litigation

In the late 1990's, the USEPA initiated an investigation under Section 114 of the Act of SIGECO's coal-fired electric generating units in commercial operation by 1977 to determine compliance with environmental permitting requirements related to repairs, maintenance, modifications, and operations changes. The focus of the investigation was to determine whether new source review permitting requirements were triggered by such plant modifications, and whether the best available control technology was, or should have been used. Numerous electric utilities were, and are currently, being investigated by the USEPA under an industry-wide review for compliance. In July 1999, SIGECO received a letter from the Office of Enforcement and Compliance Assurance of the USEPA discussing the industry-wide investigation, vaguely referring to an investigation of SIGECO and inviting SIGECO to participate in a discussion of the issues. No specifics were noted; furthermore, the letter stated that the communication was not intended to serve as a notice of violation. Subsequent meetings were conducted in September and October 1999 with the USEPA and targeted utilities, including SIGECO, regarding potential remedies to the USEPA's general allegations.

On November 3, 1999, the USEPA filed a lawsuit against seven utilities, including SIGECO. . SIGECO's suit is pending in the U.S. District Court for the Southern District of Indiana. The USEPA alleges that, beginning in 1992, SIGECO violated the Act by (1) making modifications to its Culley Generating Station in Yankeetown, Indiana without obtaining required permits (2) making major modifications to the Culley Generating Station without installing the best available emission control technology and (3) failing to notify the USEPA of the modifications. In addition, the lawsuit alleges that the modifications to the Culley Generating Station required SIGECO to begin complying with federal new source performance standards at its Culley Unit 3.

SIGECO believes it performed only maintenance, repair, and replacement activities at the Culley Generating Station, as allowed under the Act. Because proper maintenance does not require permits, application of the best available control technology, notice to the USEPA, or compliance with new source performance standards, SIGECO believes that the lawsuit is without merit, and intends to vigorously defend itself. Since the filing of this lawsuit, the USEPA has voluntarily dismissed a majority of the claims brought in its original complaint. In its original complaint, USEPA alleged significant emissions increases of three pollutants for each of four maintenance projects. Currently, USEPA is alleging only significant emission increases of a single pollutant at three of the four maintenance projects cited in the original complaint.

The lawsuit seeks fines against SIGECO in the amount of $27,500 per day per violation. However, on July 29, 2002, the Court ruled that USEPA could not seek civil penalties for two of the three remaining projects at issue in the litigation, significantly reducing potential civil penalty exposure. The lawsuit also seeks a court order requiring SIGECO to install the best available emissions technology at the Culley Generating Station. If the USEPA were successful in obtaining an order, SIGECO estimates that in response it could incur capital costs of approximately $20 million to $40 million to comply with the order. Trial is currently set to begin July 14, 2003.

The USEPA has also issued an administrative notice of violation to SIGECO making the same allegations, but alleging that violations began in 1977.

While it is possible that SIGECO could be subjected to criminal penalties if the Culley Generating Station continues to operate without complying with the permitting requirements of new source review and the allegations are determined by a court to be valid, SIGECO believes such penalties are unlikely as the USEPA and the electric utility industry have a bonafide dispute over the proper interpretation of the Act. Accordingly, the Company has recorded no accrual, and the plant continues to operate while the matter is being decided.

Information Request

On January 23, 2001, SIGECO received an information request from the USEPA under Section 114 of the Act for historical operational information on the Warrick and A.B. Brown generating stations. SIGECO has provided all information requested, and no further action has occurred.

Manufactured Gas Plants

In the past, Indiana Gas and others operated facilities for the manufacture of gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under currently applicable environmental laws and regulations, Indiana Gas and others may now be required to take remedial action if certain byproducts are found above the regulatory thresholds at these sites.

Indiana Gas has identified the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites for which it may have some remedial responsibility. Indiana Gas has completed a remedial investigation/feasibility study (RI/FS) 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. Although Indiana Gas has not begun an RI/FS at additional sites, Indiana Gas has submitted several of the sites to the IDEM's Voluntary Remediation Program and is currently conducting some level of remedial activities including groundwater monitoring at certain sites where deemed appropriate and will continue remedial activities at the sites as appropriate and necessary.

In conjunction with data compiled by environmental consultants, Indiana Gas 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, Indiana Gas has recorded costs that it reasonably expects to incur totaling approximately $20.4 million.

The estimated accrued costs are limited to Indiana Gas' proportionate share of the remediation efforts. Indiana Gas has arrangements in place for 19 of the 26 sites with other potentially responsible parties (PRP), which serve to limit Indiana Gas' share of response costs at these 19 sites to between 20% and 50%.

With respect to insurance coverage, Indiana Gas has received and recorded settlements from all known insurance carriers in an aggregate amount approximating $20.4 million.

Environmental matters related to manufactured gas plants have had no material impact on earnings since costs recorded to date approximate PRP and insurance settlement recoveries. While Indiana Gas has recorded all costs which it presently expects to incur in connection with activities at these sites, it is possible that future events may require some level of additional remedial activities which are not presently foreseen.

In October 2002, the Company received a formal information request letter from the IDEM regarding five manufactured gas plants owned and/or operated by SIGECO and not currently enrolled in the IDEM's Voluntary Remediation Program. In response, SIGECO submitted to the IDEM the results of preliminary site investigations conducted in the mid-1990's. These site investigations confirmed that based upon the conditions known at the time, the sites posed no risk to human health or the environment. Follow up reviews have recently been initiated by the Company to confirm that the sites continue to pose no such risk.

Rate and Regulatory Matters

Gas and electric operations with regard to retail rates and charges, terms of service, accounting matters, issuance of securities, and certain other operational matters specific to its Indiana customers are regulated by IURC. The retail gas operations of the Ohio operations are subject to regulation by the PUCO. Changes in prices for fuel for electric generation and purchased power are determined primarily by energy markets.

Gas Costs Proceedings

Adjustments to rates and charges related to the cost of gas charged to Indiana customers are made through gas cost adjustment (GCA) procedures established by Indiana law and administered by the IURC. Similar adjustments to the cost of gas charged to Ohio customers are made through gas cost recovery (GCR) procedures established by Ohio law and administered by the PUCO. GCA and GCR procedures involve scheduled quarterly filings and IURC and PUCO hearings to establish the amount of price adjustments for a designated future quarter. The procedures also provide for inclusion in later quarters any variances between the estimated cost of gas and actual costs incurred. This reconciliation process with regard to changes in the cost of gas sold closely matches revenues to expenses.

The IURC has also applied the statute authorizing GCA 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. Recovery of gas costs is not allowed to the extent that net operating income for the longer of (1) a 60-month period, including the twelve-month period provided in a gas cost adjustment filing, or (2) the date of the last order establishing base rates and charges exceeds the total net operating income authorized by the IURC. For the recent past, the earnings test has not affected the Company's ability to recover gas costs, and the Company does not anticipate the earnings test will restrict the recovery of gas costs in the near future.

Rate structures for gas delivery operations do not include weather normalization-type clauses that authorize the utility to recover gross margin on sales established in its last general rate case, regardless of actual weather patterns.

Commodity prices for natural gas purchases were significantly higher during the 2000 - 2001 heating season, primarily due to colder temperatures, increased demand and tighter supplies. Subject to compliance with applicable state laws, the Company's utility subsidiaries are allowed full recovery of such changes in purchased gas costs from their retail customers through these commission-approved gas cost adjustment mechanisms, and margin on gas sales should not be impacted. However, in 2001, the Company's utility subsidiaries experienced higher working capital requirements, increased expenses including unrecoverable interest costs, uncollectible accounts expense, and unaccounted for gas and some level of price sensitive reduction in volumes sold.

In March 2001, Indiana Gas and SIGECO reached agreement with the OUCC and the Citizens Action Coalition of Indiana, Inc. (CAC) regarding the matters raised by an IURC Order that disallowed $3.8 million of Indiana Gas' gas procurement costs for the 2000 - 2001 heating season which was recognized during the year ended December 31, 2000. As part of the agreement, the companies agreed to contribute an additional $1.7 million to assist qualified low income gas customers, and Indiana Gas agreed to credit $3.3 million of the $3.8 million disallowed amount to its customers' April 2001 utility bills in exchange for both the OUCC and the CAC dropping their appeals of the IURC Order. In April 2001, the IURC issued an order approving the settlement. Substantially all of the financial assistance for low income gas customers was distributed in 2001.

Fuel & Purchased Power Costs

Adjustments to rates and charges related to the cost of fuel and the net energy cost of purchased power charged to Indiana customers are made through fuel cost adjustment procedures established by Indiana law and administered by the IURC. Fuel cost adjustment procedures involve scheduled quarterly filings and IURC hearings to establish the amount of price adjustments for future quarters. The procedures also provide for inclusion in a later quarter of any variances between the estimated cost of fuel and purchased power and actual costs incurred. The order provides that any over-or-under-recovery caused by variances between estimated and actual cost in a given quarter will be included in the second succeeding quarter's adjustment factor. This continuous reconciliation of estimated incremental fuel costs billed with actual incremental fuel costs incurred closely matches revenues to expenses.

An earnings test similar to the test restricting gas cost recovery is the principal restriction to recovery of fuel cost increases. This earnings test has not affected the Company's ability to recover fuel costs, and the Company does not anticipate the earnings test will restrict the recovery of fuel costs in the near future.

As a result of an appeal of a generic order issued by the IURC in August 1999 regarding guidelines for the recovery of purchased power costs, SIGECO entered into a settlement agreement with the OUCC that provides certain terms with respect to the recoverability of such costs. The settlement, originally approved by the IURC in August 2000, has been extended by agreement through March 2003, and discussions regarding further extension of the settlement term are ongoing. Under the settlement, SIGECO can recover the entire cost of purchased power up to an established benchmark, and during forced outages, SIGECO will bear a limited share of its purchased power costs regardless of the market costs at that time. Based on this agreement, SIGECO believes it has limited its exposure to unrecoverable purchased power costs.

Transactions with ProLiance

The sale of gas and provision of other services to Indiana Gas and SIGECO by

ProLiance is subject to regulatory review through the quarterly gas cost adjustment (GCA) process administered by the IURC. The sale of gas and provision of other services to the Ohio operations by ProLiance is subject to regulatory review through the quarterly gas cost recovery (GCR) and audit process administered by the PUCO.

Specific to the sale of gas and provision of other services to Indiana Gas by ProLiance, on September 12, 1997, the IURC issued a decision finding the gas supply and portfolio administration agreements between ProLiance and Indiana Gas and ProLiance and Citizens Gas to be consistent with the public interest and that ProLiance is not subject to regulation by the IURC as a public utility. However, with respect to the pricing of gas commodity purchased from ProLiance, the price paid by ProLiance to the utilities for the prospect of using pipeline entitlements if and when they are not required to serve the utilities' firm customers, and the pricing of fees paid by the utilities to ProLiance for portfolio administration services, the IURC concluded that additional review in the GCA process would be appropriate and directed that these matters be considered further in a consolidated GCA proceeding involving Indiana Gas and Citizens Gas.

On June 4, 2002, Indiana Gas and Citizens Gas, together with the OUCC and other consumer parties, entered into and filed with the IURC a settlement setting forth the terms for resolution of all pending regulatory issues related to ProLiance, including the three pricing issues. On July 23, 2002, the IURC approved the settlement filed by the parties. The GCA proceeding has been concluded and new supply agreements between Indiana Gas, SIGECO, Citizens Gas, and ProLiance have been approved and extended through March 31, 2007. ProLiance will also have the opportunity, if it so elects, to participate in a "request for proposal" process for service to the utilities after March 31, 2007.

For past services provided to Indiana Gas by ProLiance, the Company made refunds to Indiana Gas' retail customers pursuant to the settlement totaling $6.4 million in the fourth quarter of 2002. A subsidiary of Vectren's nonregulated operations has indemnified Indiana Gas for the amount of the refund as well as any other amounts incurred as a result of the settlement. Accordingly, the refund had no effect on operating margin or net income.

In addition to the above, the IURC order also provides that:

- A portion of the utilities' natural gas will be purchased through a gas cost incentive mechanism that shares price risk and reward between the utilities and customers;
- Beginning in 2004, ProLiance will provide the utilities with an interstate pipeline transport and storage service price discount, thus providing additional savings to customers;
- As ProLiance continues to provide the utilities with its supply services, Citizens Gas and Vectren will together annually provide an additional $2 million per year in customer benefits in 2003, 2004, and 2005.

Critical Accounting Policies

Management is required to make judgements, 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. Note 2 to the consolidated financial statements describes the significant accounting policies and methods used in the preparation of the consolidated financial statements. Certain estimates used in the financial statements are subjective and use variables that require judgement. These include the estimates to perform goodwill and other asset impairments tests. The Company makes other estimates in the course of accounting for unbilled revenue, the effects of regulation, and intercompany allocations 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 depreciation of utility plant, the valuation of derivative contracts, and the allowance for doubtful accounts, among others. Actual results could differ from these estimates.

Goodwill

Pursuant to SFAS No. 142, the Company performed an initial impairment analysis of its goodwill, all of which resides in the Gas Utility Services operating segment. Also consistent with SFAS 142, goodwill is tested for impairment annually at the beginning of the year and more frequently if events or circumstances indicate that an impairment loss has been incurred. Impairment tests are performed at the reporting unit level which the Company has determined to be consistent with its Gas Utility Services operating segment as identified in Note 14 to the consolidated financial statements. An impairment test performed in accordance with SFAS 142 requires that a reporting unit's fair value be estimated. The Company used a discounted cash flow model 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 was in excess of the carrying amount and therefore resulted in no impairment.

Estimating fair value using a discounted cash flow model is subjective and requires significant judgement 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 results in no impairment charge.

Impairment Review of Investments

The Company has investments in unconsolidated affiliates, including notes receivable convertible into equity interests. On a periodic basis and when events occur that may cause one of these investments to be impaired, the Company performs an impairment analysis. An impairment analysis of notes receivable usually involves the comparison of the investment's estimated free cash flows to the stated terms of the note. An impairment analysis of investments in unconsolidated affiliates involves comparison of the investment's estimated fair value to its carrying amount. Fair value is estimated using primarily using discounted cash flow analyses. Calculating free cash flows and fair value using the above methods is subjective and requires significant judgement in growth assumptions, longevity of cash flows, and discount rates (for fair value calculations).

During 2002, the Company performed impairment tests on certain investments using both free cash flows and discounted cash flows. No impairment charges resulted from these analyses. For these impairment tests, a 100 basis point adverse change in the discount rate used to estimate discounted cash flow or a 10% adverse change in the cash flow growth assumption used to estimate free cash flows would have resulted in no impairment charge.

Unbilled Revenues

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. The Company uses actual units billed during the month to allocate unbilled units. Those allocated units are multiplied by rates in effect during the month to calculate unbilled revenue at balance sheet dates. While certain estimates are used in the calculation of unbilled revenue, these estimates are not subject to near term changes.

Regulation

At each reporting date, the Company reviews current regulatory trends in the markets in which it operates. This review involves judgement 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 SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). 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 of SFAS 71, 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. In the unlikely event of a change in the current regulatory environment, such write-offs and impairment charges could be significant.

Intercompany Allocations

Support Services

Vectren and certain subsidiaries of Vectren provided corporate, general and administrative services to the Company including legal, finance, tax, risk management, and human resources, which includes charges for restricted stock compensation and for pension and other postretirement benefits not directly charged to subsidiaries. These costs have been allocated using various allocators, primarily number of employees, number of customers and/or revenues. Allocations are based on 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. An allocation of expense is determined by Vectren's actuaries, comprised of only service cost and interest on that service cost, by subsidiary based on headcount at each measurement date. These costs are directly charged to individual subsidiaries. Other components of costs (such interest cost from prior service and asset returns) are charged to individual subsidiaries through the corporate allocation process discussed above. Plan assets nor the FAS 87/106 liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. Further, Vectren satisfies the future funding requirements of plans and the payment of benefits from general corporate assets. 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 annually measures its obligations on September 30.

Vectren estimates the expected return on plan assets, discount rate, rate of compensation increase, and future health care costs, among other things, and relies on 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 2002 annual costs and the ending benefit obligations recognized in the consolidated financial statements: a discount rate of 6.75%, an expected return on plan assets before expenses of 9.00%, a rate of compensation increase of 4.25%, and a health care cost trend rate of 10% in 2002 declining to 5% in 2006. During 2002, Vectren reduced the discount rate and rate of compensation increase by 50 basis points from those assumptions used in 2001 due to the general decline in interest rates and other market conditions that occurred in 2002. Future changes in health care costs, work force demographics, interest rates, or plan changes could significantly affect the estimated cost of these future benefits that are allocated to VUHI and its subsidiaries.

Impact of Recently Issued Accounting Guidance on Future Operations

EITF 02-03

In October 2002, the EITF reached a final consensus in EITF Issue 02-03 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) that gains and losses (realized and unrealized) on all derivative instruments within the scope of SFAS 133 should be shown net in the income statement, whether or not settled physically, if the derivative instruments are held for "trading purposes." The consensus rescinded EITF Issue 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10) as well as other decisions reached on energy trading contracts at the EITF's June 2002 meeting.

The Company's non-firm wholesale power marketing operations enter into contracts that are derivatives as defined by SFAS 133, but these operations do not meet the definition of energy trading activities based upon the provisions in EITF 98-10. Currently, the Company uses a gross presentation to report the results of these operations as described in Note 12 of the consolidated financial statements. The Company has re-evaluated its portfolio of derivative contracts and has determined gross presentation remains appropriate.

SFAS 143

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. Any costs of removal recorded in accumulated depreciation pursuant to regulatory authority will require disclosure in future periods. The Company adopted this statement on January 1, 2003. The adoption was not material to the Company's results of operations or financial condition.

FASB Interpretation (FIN) 45

In November 2002, the FASB issued Interpretation 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 clarifies the requirements for a guarantor's accounting for and disclosure of certain guarantees issued and outstanding and that a guarantor is required to recognize, at the inception of a guarantee, a liability for the obligations it has undertaken. The objective of the initial measurement of that liability is the fair value of the guarantee at its inception. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. Although management is still evaluating the impact of FIN 45 on its financial position and results of operations, the adoption is not expected to have a material effect.

FIN 46

In January 2003, the FASB issued Interpretation 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 addresses consolidation by business enterprises of variable interest entities and significantly changes the consolidation requirements for those entities. FIN 46 is intended to achieve more consistent application of consolidation policies to variable interest entities and, thus improves comparability between enterprises engaged in similar activities when those activities are conducted through variable interest entities. FIN 46 applies to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. FIN 46 applies to the Company's third quarter for variable interest entities in which the Company holds a variable interest acquired before February 1, 2003. Although management is still evaluating the impact of FIN 46 on its financial position and results of operations, the adoption is not expected to have a material effect.

Financial Condition

Within Vectren's consolidated group, VUHI funds short-term and long-term financing needs of the regulated operations. Vectren does not guarantee VUHI's debt. VUHI's currently outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. Prior to VUHI's formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have debt outstanding funded solely by their operations. VUHI's operations have historically funded Vectren's common stock dividends.

In November 2002, Moody's Investors Service (Moody's) downgraded the senior unsecured debt of VUHI, Indiana Gas, and SIGECO (from A2 to Baa1) as well as SIGECO's senior secured debt (from A1 to A3) and SIGECO's pollution control revenue bonds (from VMIG 1 to VMIG 2). In addition, VUHI's commercial paper program was also downgraded (from P-1 to P-2). The reasons cited for the downgrades included weaker credit and fixed charge coverage measures compared to A2 peers, resulting from the prior integration and restructuring costs and warm winter of 2001 and 2002; and lack of weather normalization-type clauses that authorize the utilities to recover gross margin on sales regardless of actual weather patterns.

VUHI's and Indiana Gas' credit ratings on outstanding senior unsecured debt at December 31, 2002 are A-/Baa1 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's, respectively. SIGECO's credit ratings on outstanding senior unsecured debt at December 31, 2002 are BBB+/Baa1. SIGECO's credit ratings on outstanding secured debt at December 31, 2002 are A-/A3. VUHI's commercial paper has a credit rating of A-2/P-2. Moody's current outlook is stable while Standard and Poor's current outlook is negative. The ratings of Standard and Poor's and Moody's are categorized 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.

The Company's consolidated equity capitalization objective is 40-55% of total capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, and seasonal factors that affect the Company's operation. The Company's equity component was 46% and 45% of total capitalization, including current maturities of long-term debt and long-term debt subject to tender, at December 31, 2002 and 2001, respectively.

The Company expects the majority of its capital expenditures and debt security redemptions to be provided by internally generated funds. However, additional permanent financing may be required due to significant capital expenditures for NOx compliance equipment at SIGECO and plans to further strengthen the Company's capital structure and the capital structures of its utility subsidiaries. These plans may include the issuance of new equity to Vectren and debt and the calling of certain long-term debt at SIGECO and Indiana Gas. Specific to the NOx compliance project, the Company is authorized an 8 percent return on its capital investments through approved rider mechanisms.

Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary and historical source of liquidity to fund working capital requirements has been cash generated from operations. Cash flow from operations increased during the year ended December 31, 2002 compared to 2001 by $92.1million and increased $150.3 million in 2001 compared to 2000. The primary reasons for the increases are due to favorable changes in working capital due to a return to lower gas prices and increased earnings before non-cash charges.

Financing Cash Flow

Although working capital requirements are generally funded by cash flow from operations, the Company uses short-term borrowings to supplement working capital needs when accounts receivable balances are at their highest and gas storage is refilled. Additionally short-term borrowings are required for capital projects and investments until they are permanently financed.

Cash flow required for financing activities of $53.6million for the year ended December 31, 2002 includes an increase in borrowings outstanding over 2001 of $16.3 million and $69.7 million in dividends paid to Vectren compared to 2001. Borrowings have increased due to the use of short-term borrowing for non-utility property and NOx expenditures.

Cash flow from financing activities of $33.9 million for the year ended December 31, 2001 includes $38.1 million of reductions in borrowings and preferred stock and $91.6 million in dividends paid to Vectren, offset by additional capital contributions of $164.4 million. During 2001, $508.4 million of net proceeds from debt issuances and capital contributions were utilized to pay down short-term borrowings and strengthen VUHI's balance sheet.

Financing the Ohio Operations Purchase
On October 31, 2000, the acquisition of the Ohio operations was completed for a purchase price of approximately $471 million. Commercial paper and $150.0 million in floating rate notes were issued to fund the purchase. During 2001, the Company refinanced these interim borrowing arrangements with permanent financing in the form of new equity and long-term debt, as described below.

In January 2001, Vectren filed a registration statement with the Securities and Exchange Commission with respect to a public offering of 5.5 million shares of new common stock. In February 2001, the registration became effective, and an agreement was reached to sell approximately 6.3 million shares (the original 5.5 million shares, plus an over-allotment option of 0.8 million shares) to a group of underwriters. The net proceeds from the sale of common stock totaled $129.4 million. These proceeds were contributed to VUHI as an additional capital contribution.

In September 2001, VUHI filed a shelf registration statement with the Securities and Exchange Commission for $350.0 million aggregate principal amount of unsecured senior notes. In October 2001, VUHI issued senior unsecured notes with an aggregate principal amount of $100.0 million and an interest rate of 7.25% (the October Notes), and in December 2001, issued the remaining aggregate principal amount of $250.0 million at an interest rate of 6.625% (the December Notes). The December Notes were priced at 99.302% to yield 6.69% to maturity.

These issues have no sinking fund requirements, and interest payments are due quarterly for the October Notes and semi-annually for the December Notes. The October Notes are due October 2031, but may be called by the Company, in whole or in part, at any time after October 2006 at 100% of the principal amount plus any accrued interest thereon. The December Notes are due December 2011, but may be called by the Company, in whole or in part, at any time for an amount equal to accrued and unpaid interest, plus the greater of 100% of the principal amount or the sum of the present values of the remaining scheduled payments of principal and interest, discounted to the redemption date on a semi-annual basis at the Treasury Rate, as defined in the indenture, plus 25 basis points.

Both issues are guaranteed by VUHI's three operating utility companies: SIGECO, Indiana Gas, and VEDO. These guarantees of VUHI's debt are full and unconditional and joint and several. The net proceeds from the sale of the senior notes and settlement of hedging arrangements totaled $344.0 million

Other Financing Transactions

In December 2001, Vectren contributed additional capital of $35.0 million. The proceeds were used to repay short-term borrowings.

In September 2001, the Company notified holders of SIGECO's 4.80%, 4.75%, and 6.50% preferred stock of its intention to redeem the shares. The 4.80% preferred stock was redeemed at $110.00 per share, plus $1.35 per share in accrued and unpaid dividends. Prior to the redemption, there were 85,519 shares outstanding. The 4.75% preferred stock was redeemed at $101.00 per share, plus $0.97 per share in accrued and unpaid dividends. Prior to the redemption, there were 3,000 shares outstanding. The 6.50% preferred stock was redeemed at $104.23 per share, plus $0.73 per share in accrued and unpaid dividends. Prior to the redemption, there were 75,000 shares outstanding. The total redemption price was $17.7 million.

In December 2000, Indiana Gas issued $20.0 million of 15-Year Insured Quarterly (IQ) Notes at an interest rate of 7.15% and $50.0 million of 30-Year IQ Notes at an interest rate of 7.45%. Indiana Gas has the option to redeem the 15-Year IQ Notes, in whole or in part, from time to time on or after December 15, 2004 and the option to redeem the 30-Year IQ Notes in whole or in part, from time to time on or after December 15, 2005. The IQ notes have no sinking fund requirements. The net proceeds totaling $67.9 million were used to repay outstanding commercial paper.

Investing Cash Flow

Cash required for investing activities of $218.7 million for the year ended December 31, 2002 includes $217.3 million of requirements for capital expenditures. Investing activities for 2001 were $215.3 million. The $3.4 million increase in requirements occurring in 2002 is principally the result of additional capital expenditures for NOx compliance and investments in deferred compensation funding arrangements, offset by proceeds received from intercompany notes receivable.

Cash required for investing activities for the year ended December 31, 2001 includes $202.8 million of requirements for capital expenditures. Investing activities for the year ended December 31, 2000 were $595.0 million. The $379.7 million decrease occurring in 2001 is principally the result of the acquisition of the Ohio operations in 2000, offset by increased capital expenditures for utility plant and non-utility plant infrastructure.

Available Sources of Liquidity

At December 31, 2002, the Company has $330.0 million of short-term borrowing capacity, of which approximately $90.9 million is available. Subsequent to December 31, 2002, the Company increased its capacity $145.0 million to $475.0 million. Effective January 1, 2003, Vectren transferred certain assets that primarily support the regulated operations from other wholly owned subsidiaries to VUHI. This transfer of assets will take advantage of the greater borrowing capacity available to VUHI.

Prior to 2001, Vectren purchased shares from the open market to satisfy issuances of common stock pursuant to its dividend reinvestment plan and stock option plans. In 2001, Vectren began issuing new shares to satisfy exercised stock options and beginning in 2003 will issue new shares to satisfy dividend reinvestment plan requirements. Management estimates these new equity issues will add approximately $5 million per year that may be utilized to support VUHI's operations.

Potential & Future Uses of Liquidity

The following is a summary of certain obligations and commitments at December 31, 2002:

(In millions)	2003	2004	2005	2006	2007	Thereafter
Short-term debt due to third parties	$ 239.1	$ -	$ -	$ -	$ -	$ -
Short-term debt due to other Vectren companies	86.9	-	-	-	-	-
Long-term debt (1)	16.0	15.0	-	-	6.5	850.6
Long-term debt to be called (2)	23.8	-	-	-	-	-
Firm natural gas purchase commitments	89.5	21.3	3.6	-	-	-
Total	$ 455.3	$ 36.3	$ 3.6	$ -	$ 6.5	$ 850.6

(1) Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. These provisions allow holders to put debt back to the Company at face value or the Company to call debt at face value or at a premium. Long-term debt subject to tender during the years following 2002 (in millions) is $26.6 in 2003, $13.5 in 2004, $10.0 in 2005, $53.7 in 2006, $20.0 in 2007 and $120.0 thereafter.

(2) On January 15, 2003, the Company called the remaining $23.8 million of Indiana Gas' 9.375% private placement notes originally due in 2021. Since the proceeds to repay the notes were generated from short-term borrowings, these notes are classified in current maturities of long-term debt at December 31, 2002.

Planned Capital Expenditures & Investments

Capital expenditures for the five-year period 2003 - 2007 will require significant investments and include expenditures for non-utility plant that will primarily support utility operations and for NOx compliance. Capital expenditures are estimated as follows:

In millions	2003	2004	2005	2006	2007
Capital expenditures					
Utility plant (1)	$ 204.8	$ 236.5	$ 184.9	$ 145.1	$ 135.4
Non-utility plant	22.3	27.8	10.5	16.4	11.3
Total capital expenditures	$ 227.1	$ 264.3	$ 195.4	$ 161.5	$ 146.7

(1) Includes expenditures for NOx compliance of approximately $83.0 million in

2003, $79.0 million in 2004, $23.7 million in 2005, and $4.6 million in 2006.

Guarantees

Vectren's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of VUHI's $325.0 million commercial paper program, of which $239.1 million is outstanding at December 31, 2002 and VUHI's $350.0 million unsecured senior notes outstanding at December 31, 2002. The guarantees are full and unconditional and joint and several, and VUHI has no subsidiaries other than the subsidiary guarantors.

Pension and Postretirement Funding Obligations

Vectren has not made significant contributions to its qualified pension plans in recent years. Due to poor market performance during 2000-2002, it will be necessary for Vectren to make contributions to benefits plans in the coming years. Management currently estimates that the qualified pension plans will require Company contributions of less than $1 million in 2003 and between $5 million and $10 million in 2004 and 2005. VUHI may be called upon to fund a portion of these contributions.

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," and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to fossil fuel costs; unanticipated changes to gas supply 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.
- Increased competition in the energy environment including 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 or regulatory 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 an economic downturn, inflation rates, and monetary fluctuations.
- 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 our business, financial condition or liquidity resulting from a change in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee workforce factors including changes in key executives, collective bargaining agreements with union employees, or work stoppages.
- Legal and regulatory delays and other obstacles associated with mergers, acquisitions, and investments in joint ventures.
- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims, and other matters, including, but not limited to, those described in Management's Discussion and Analysis of Results of Operations and Financial Condition.
- Changes in federal, state or local legislature requirements, such as changes in tax laws or rates, environmental laws and regulations.

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

ITEM 7A. QUALITATIVE AND 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 to mitigate risk.

The Company also executes derivative contracts in the normal course of operations while buying and selling commodities and other fungible goods to be used in operations and while optimizing generation assets. The Company does not execute derivative contracts for speculative or trading purposes.

Commodity Price Risk

The Company's regulated operations have limited exposure to commodity price risk for purchases and sales of natural gas and electricity for retail customers due to current Indiana and Ohio regulations, which subject to compliance with those regulations, allow for recovery of such purchases through natural gas and fuel cost adjustment mechanisms.

Electric sales and purchases in the wholesale power market and other commodity-related operations are exposed to commodity price risk associated with fluctuating electric power and other commodity prices. Other commodity operations include sales of electricity to certain municipalities and large industrial customers.

The Company's non-firm wholesale power marketing operations manage the utilization of its available electric generating capacity by entering into forward and option contracts that commit the Company to purchase and sell electricity in the future. Commodity price risk results from forward positions that commit the Company to deliver electricity. The Company mitigates price risk exposure with planned unutilized generation capability and offsetting forward purchase contracts.

The Company's other commodity-related operations involve the purchase and sale of commodities, including electricity, to meet customer demands and operational needs. These operations also enter into forward contracts that commit the Company to purchase and sell commodities in the future. Price risk from forward positions that commit the Company to deliver commodities is mitigated using insurance contracts and offsetting forward purchase contracts.

Open positions in terms of price, volume, and specified delivery points may occur and are managed using methods described above and frequent management reporting.

Market risk is measured by management as the potential impact on pre-tax earnings resulting from a 10% adverse change in the forward price of commodity prices on outstanding market sensitive financial instruments (all contracts not expected to be settled by physical receipt or delivery). For the years ended December 31, 2002 and 2001, a 10% adverse change in commodity forward prices on market sensitive financial instruments would have decreased pre-tax earnings by approximately $1.5 million and $2.0 million, respectively.

Interest Rate Risk

The Company is exposed to interest rate risk associated with its adjustable rate borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on operations. The Company tries to limit the amount of adjustable rate borrowing arrangements exposed to short-term interest rate volatility to a maximum of 25% of total debt. However, there are times when this targeted level of interest rate exposure may be exceeded. At December 31, 2002, such obligations represented 26% of the Company's total debt portfolio. To manage this exposure, the Company may periodically use derivative financial instruments to reduce earnings fluctuations caused by interest rate volatility.

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 including bank notes, lines of credit, commercial paper, and certain adjustable rate long-term debt instruments. At December 31, 2002 and 2001, the combined borrowings under these facilities totaled $319.5 million and $296.7 million, respectively. Based upon average borrowing rates under these facilities during the years ended December 31, 2002 and 2001, an increase of 100 basis points (1%) in the rates would have increased interest expense by $2.3 million and $5.4 million, respectively. Of the 2001 exposure, approximately $1.5 million would have been offset by an interest rate swap designated to hedge such exposure.

Other Risks

By using forward purchase contracts and derivative financial instruments to manage risk, the Company exposes itself 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 a diversified base of 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.

Although the Company's regulated operations are exposed to limited commodity price risk, volatile natural gas prices can result in higher working capital requirements; increased expenses including unrecoverable interest costs, uncollectible accounts expense, and unaccounted for gas; and some level of price sensitive reduction in volumes sold.

ITEM 8. Financial Statements and Supplementary Data

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Vectren Utility Holdings, Inc. (VUHI) is responsible for the preparation of the consolidated financial statements and the related financial data contained in this report. The financial statements are 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 the data in this report, including required estimates and judgments, is the responsibility of management. Management maintains a system of internal control and utilizes an internal auditing program to provide reasonable assurance of compliance with Company policies and procedures and the safeguard of assets.

The board of directors of VUHI's parent company, Vectren Corporation, pursues its responsibility for these financial statements through its audit committee, which meets periodically with management, the internal auditors and the independent auditors, to assure that each is carrying out its responsibilities. Both the internal auditors and the independent auditors meet with the audit committee of Vectren Corporation's board of directors, with and without management representatives present, to discuss the scope and results of their audits, their comments on the adequacy of internal accounting control and the quality of financial reporting.

/S/ Niel C. Ellerbrook
Niel C. Ellerbrook
Chairman & Chief Executive Officer
February 26, 2003

INDEPENDENT AUDITORS' REPORT

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 as of December 31, 2002 and 2001, 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, 2002. Our audits also included the financial statement schedules listed in the Table of Contents at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 2, effective January 1, 2002, the Company adopted Statement of Financial Accounting Standards ("SFAS") 142, "Goodwill and Other Intangibles." As discussed in Note 12, effective, January 1, 2001, the Company adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

As discussed in Note 3, the accompanying 2001 and 2000 financial statements have been restated.

/S/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 26, 2003 (June 2, 2003 as to Notes 3 and 17)

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

	At December 31,	
	2002	2001
ASSETS		(As Restated, See Note 3)
Current Assets		
Cash & cash equivalents	$ 10.5	$ 5.2
Accounts receivable-less reserves of $5.5 & $5.1, respectively	131.9	123.1
Receivables due from other Vectren companies	56.3	86.3
Accrued unbilled revenues	112.7	77.1
Inventories	56.0	54.8
Recoverable fuel & natural gas costs	22.1	70.2
Prepayments & other current assets	86.5	82.8

Total current assets	476.0	499.5
Utility Plant		
Original cost	3,037.2	2,906.1
Less: accumulated depreciation & amortization	1,389.0	1,308.2
Net utility plant	1,648.2	1,597.9
Investments in unconsolidated affiliates	2.4	3.5
Other investments	21.9	20.0
Non-utility property-net	139.2	85.0
Goodwill-net	202.2	201.5
Regulatory assets	75.2	67.8
Other assets	5.3	14.1
TOTAL ASSETS	$ 2,570.4	$ 2,489.3

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,	
	2002	2001
LIABILITIES & SHAREHOLDER'S EQUITY		(As Restated, See Note 3)
Current Liabilities		
Accounts payable	$ 74.8	$ 79.4
Accounts payable to affiliated companies	85.6	37.4
Payables due to other Vectren companies	69.8	51.6
Accrued liabilities	83.2	95.2
Short-term borrowings	239.1	274.2
Short-term borrowings due to other Vectren companies	86.9	29.0
Current maturities of long-term debt	39.8	1.3
Long-term debt subject to tender	26.6	11.5
Total current liabilities	705.8	579.6
Long-Term Debt-Net of Current Maturities & Debt Subject to Tender	841.2	900.9
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	172.3	176.5
Deferred credits & other liabilities	82.2	92.9
Total deferred credits & other liabilities	254.5	269.4
Commitments & Contingencies (Notes 9 - 11)		
Cumulative, Redeemable Preferred Stock of a Subsidiary	0.3	0.5

Common Shareholder's Equity		
Common stock (no par value)	385.7	385.7
Retained earnings	382.4	355.0
Accumulated other comprehensive income (loss)	0.5	(1.8)
Total common shareholder's equity	768.6	738.9
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$ 2,570.4	$ 2,489.3

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,		
	2002	2001	2000
OPERATING REVENUES		(As Restated, See Note 3)	
Gas utility	$ 909.0	$1,019.6	$ 820.4
Electric utility	608.1	381.2	334.4
Other	0.3	0.2	0.3
Total operating revenues	1,517.4	1,401.0	1,155.1
OPERATING EXPENSES			
Cost of gas sold	571.8	708.9	552.5
Fuel for electric generation	81.6	74.4	75.7
Purchased electric energy	296.3	86.9	36.4
Other operating	198.6	212.1	180.6
Merger & integration costs	-	2.8	32.7
Restructuring costs	-	15.0	-
Depreciation & amortization	110.7	117.9	104.6
Taxes other than income taxes	50.7	51.6	36.5
Total operating expenses	1,309.7	1,269.6	1,019.0
OPERATING INCOME	207.7	131.4	136.1
OTHER INCOME			
Other - net	7.1	5.6	4.3
Equity in earnings of unconsolidated affiliates	(1.8)	(0.5)	-
Total other income	5.3	5.1	4.3
Interest expense	69.1	70.7	46.4
INCOME BEFORE INCOME TAXES	143.9	65.8	94.0
Income taxes	46.8	21.3	37.1
Preferred dividend requirements of			

subsidiary	-	0.8	1.0
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	97.1	43.7	55.9
Cumulative effect of change in accounting principle - net of tax	-	1.1	-
NET INCOME	$ 97.1	$ 44.8	$ 55.9

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,		
	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES	(As Restated, See Note 3)		
Net income	$ 97.1	$ 44.8	$ 55.9
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	110.7	117.9	104.6
Deferred income taxes & investment tax credits	(23.4)	(14.9)	12.9
Pension and post-retirement expense	6.5	5.7	8.8
Equity in earnings of unconsolidated affiliates	1.8	0.5	-
Net unrealized loss (gain) on derivative instruments, including cumulative effect of change in accounting principle	3.6	(3.3)	-
Other non-cash charges- net	8.4	14.0	(1.2)
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenue	(28.1)	78.9	(231.0)
Inventories	(1.2)	38.4	15.9
Recoverable fuel & natural gas costs	48.1	25.9	(82.3)
Prepayments & other current assets	(9.4)	(11.3)	(36.8)
Accounts payable, including to Vectren companies & affiliated companies	73.2	(87.7)	184.4
Accrued liabilities	0.1	(10.3)	0.7
Changes in noncurrent assets	(1.2)	(4.2)	2.5
Changes in noncurrent liabilities	(8.6)	(9.1)	0.7
Net cash flows from operating activities	277.6	185.3	35.1
CASH FLOWS (REQUIRED FOR) FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt - net of issuance costs	-	344.0	67.9
Additional capital contribution	-	164.4	-
Short-term notes payable	-	-	150.0
Other proceeds	-	-	1.6
Requirements for:			

Dividends on common stock	(69.7)	(91.6)	(60.6)
Retirement of long-term debt	(6.5)	(7.3)	(0.7)
Redemption of preferred stock of subsidiary	(0.2)	(17.7)	(2.0)
Retirement of short-term notes payable	-	(150.0)	-
Dividends on preferred stock of subsidiary	-	(0.8)	(1.0)
Net change in short-term borrowings, including to other Vectren companies	22.8	(207.1)	405.2
Net cash flows (required for) from financing activities	(53.6)	33.9	560.4
CASH FLOWS (REQUIRED FOR) INVESTING ACTIVITIES			
Proceeds from other investing activities	10.4	1.5	-
Requirements for:			
Capital expenditures, excluding AFUDC equity	(217.3)	(202.8)	(118.7)
Acquisition of Ohio operations	-	(2.2)	(469.2)
Other investments	(11.8)	(11.8)	(7.1)
Net cash flows (required for) investing activities	(218.7)	(215.3)	(595.0)
Net increase (decrease) in cash & cash equivalents	5.3	3.9	0.5
Cash & cash equivalents at beginning of period	5.2	1.3	0.8
Cash & cash equivalents at end of period	$ 10.5	$ 5.2	$ 1.3

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

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

	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at January 1, 2000, As Reported	$ 221.3	$ 405.7	$ -	$ 627.0
Restatement adjustment		1.7		1.7
Balance at January 1, 2000, As Restated	221.3	407.4	-	628.7
Net income & comprehensive income, As Restated		55.9		55.9
Common stock dividends		(60.6)		(60.6)
Other		0.3		0.3
Balance at December 31, 2000, As Restated	221.3	403.0	-	624.3
Comprehensive income:				
Net income, As Restated		44.8		44.8
Minimum pension liability adjustment & other-net of tax			(1.8)	(1.8)

Total comprehensive income, As Restated				43.0
Common stock:				
Additional capital contribution	164.4			164.4
Dividends		(91.6)		(91.6)
Loss on extinguishment of preferred stock		(1.2)		(1.2)
Balance at December 31, 2001, As Restated	385.7	355.0	(1.8)	738.9
Comprehensive income:				
Net income		97.1		97.1
Minimum pension liability adjustments & other - net of tax			2.3	2.3
Total comprehensive income				99.4
Common stock dividends		(69.7)		(69.7)
Balance at December 31, 2002	$ 385.7	$ 382.4	$ 0.5	$ 768.6

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

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

1. Organization and Nature of Operations

Overview
Vectren Utility Holdings, Inc. (VUHI or the Company), 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), formerly a wholly owned subsidiary of Indiana Energy, Inc. (Indiana Energy), Southern Indiana Gas and Electric Company (SIGECO), formerly a wholly owned subsidiary of SIGCORP, Inc. (SIGCORP), and the Ohio operations. VUHI also has assets that provide information technology and other services to the utilities.

Indiana Gas provides natural gas distribution and transportation services to a diversified customer base in 49 of Indiana's 92 counties. SIGECO provides electric generation, transmission, and distribution services to 8 counties in southwestern Indiana, including counties surrounding Evansville, and participates in the wholesale power market. SIGECO also provides natural gas distribution and transportation services to 10 counties in southwestern Indiana, including counties surrounding Evansville. The Ohio operations provide natural gas distribution and transportation services to 17 counties in west central Ohio, including counties surrounding Dayton.

Vectren is an energy and applied technology holding company headquartered in Evansville, Indiana. The Company was organized on June 10, 1999 solely for the purpose of effecting the merger of Indiana Energy and SIGCORP. On March 31, 2000, the merger of Indiana Energy with SIGCORP and into Vectren was consummated with a tax-free exchange of shares and has been accounted for as a pooling-of-interests in accordance with APB Opinion No. 16 "Business

Combinations" (APB 16).

Both Vectren and VUHI are exempt from registration pursuant to Section 3(a)(1) and 3(c) of the Public Utility Holding Company Act of 1935.

Acquisition of the Natural Gas Distribution Assets of The Dayton Power and Light Company

On October 31, 2000, the Company acquired the natural gas distribution assets of The Dayton Power and Light Company for $471 million, including transaction costs. The acquisition has been accounted for as a purchase transaction in accordance with APB 16, and accordingly, the results of operations of the acquired assets are included in the Company's financial results since the date of acquisition.

The Company acquired the natural gas distribution assets as a tenancy in common through two separate wholly owned subsidiaries. Vectren Energy Delivery of Ohio, Inc. (VEDO) holds a 53% undivided ownership interest in the assets, and Indiana Gas holds a 47% undivided ownership interest. VEDO is the operator of the assets, and these operations are referred to as "the Ohio operations."

The purchase price was allocated to the assets and liabilities acquired based on the fair value of those assets and liabilities as of the acquisition date. Because of the regulatory environment in which the Ohio operations operate, the book value of rate-regulated assets and liabilities is generally considered to be fair value. Goodwill, in the amount of $202.5 million, was recognized for the excess amount of the purchase price paid over the fair value of the net assets acquired.

Had the acquisition of the Ohio operations occurred on January 1, 2000, pro forma operating revenues and net income for the year ended December 31, 2000 would have been $1,339.1 million and $51.1 million, respectively. This pro forma information is not necessarily indicative of the results that actually would have occurred if the transaction had been consummated at the beginning of the periods presented and is not intended to be a projection of future results.

2. Summary of Significant Accounting Policies

A. Principles of Consolidation

The accompanying consolidated financial statements for the period prior to March 31, 2000 reflect the Company on a historical basis as restated for the effects of the combination of entities under common control whereby Indiana Gas and SIGECO became subsidiaries of VUHI. The consolidated financial statements include the accounts of the Company and its wholly owned and majority owned subsidiaries, after elimination of intercompany transactions.

For the three months ended March 31, 2000, operating revenues and net income contributed by the predecessor companies were $171.6 million and $8.8 million, respectively, by Indiana Gas and $102.2 million and $4.0 million, respectively, by SIGECO.

B. 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 paid during the periods reported for interest, income taxes, and acquired assets and liabilities follows:

	Year Ended December 31,		
In millions	2002	2001	2000

Cash paid for			
Interest	$ 58.4	$ 63.5	$ 45.2
Income taxes	63.3	46.7	44.8
Details of acquisition (Note 1)			
Book value of assets acquired	$ -	$ 1.6	$ 275.2
Liabilities assumed	-	-	7.9
Net assets acquired	$ -	$ 1.6	$ 267.3

C. Inventories
Inventories consist of the following:

	At December 31,	
In millions	2002	2001
Gas in storage - at LIFO cost	$ 25.4	$ 24.4
Materials & supplies	15.8	16.5
Fuel (coal & oil) for electric generation	10.0	9.5
Gas in storage - at average cost	3.3	0.8
Other	1.5	3.6
Total inventories	$ 56.0	$ 54.8

Based on the average cost of gas purchased during December, the cost of replacing gas in storage carried at LIFO cost exceeded LIFO cost at December 31, 2002 and 2001 by approximately $32.7 million and $17.9 million, respectively. Gas in storage of the Indiana regulated operations is stated at LIFO. All other inventories are carried at average cost.

D. Utility Plant & Depreciation
Utility plant is stated at historical cost, including AFUDC. Depreciation of utility property is provided using the straight-line method over the estimated service lives of the depreciable assets.

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	2002		2001	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$1,622.0	3.8%	$1,523.0	3.6%
Electric utility plant	1,211.1	3.3%	1,148.9	3.3%
Common utility plant	41.6	2.6%	41.3	2.6%
Construction work in progress	162.5	-	192.9	-

Total original cost	$3,037.2	$2,906.1

AFUDC represents the cost of borrowed and equity funds used for construction purposes and is charged to construction work in progress during the construction period and is included in other - net in the Consolidated Statements of Income. The total AFUDC capitalized into utility plant and the portion of which was computed on borrowed and equity funds for all periods reported follows:

	Year Ended December 31,		
In millions	2002	2001	2000
AFUDC - borrowed funds	$ 3.1	$ 2.1	$ 2.4
AFUDC - equity funds	2.2	2.5	2.6
Total AFUDC capitalized	$ 5.3	$ 4.6	$ 5.0

Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred. When property that represents a retirement unit is replaced or removed, the cost of such property is credited to utility plant, and such cost, together with the cost of removal less salvage, is charged to accumulated depreciation.

E. Non-Utility Property
The depreciation of non-utility property is charged against income over its estimated useful life (ranging from 5 to 40 years), using the straight-line method of depreciation. Repairs and maintenance, which are not considered improvements and do not extend the useful life of the non-utility property, are charged to expense as incurred. When non-utility property is retired, or otherwise disposed of, the asset and accumulated depreciation are removed, and the resulting gain or loss is reflected in income. Non-utility property is presented net of accumulated depreciation and amortization totaling $83.8 million and $69.9 million as of December 31, 2002 and 2001, respectively. Interest capitalized on non-utility projects approximated $0.2 million in 20021 and was not significant in 2002 or 2000.

F. Impairment Review of Long-Lived Assets
Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This review is performed in accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS 144), which the Company adopted as required on January 1, 2002. SFAS 144 establishes one accounting model for all impaired long-lived assets and long-lived assets to be disposed of by sale or otherwise. SFAS 144 replaced authoritative guidance in SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (SFAS 121) and certain aspects of APB Opinion No. 30, "Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business." SFAS 144 retains the framework of SFAS 121 and requires the evaluation for impairment involve the comparison of an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the carrying value of the asset is impaired, an impairment charge would be recorded based on the difference between the asset's 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.

G. Goodwill
Goodwill arising from past business combinations, such as the Company's acquisition of the Ohio operations, is accounted for in accordance with SFAS No.

142, "Goodwill and Other Intangible Assets" (SFAS 142). The Company adopted SFAS 142, as required on January 1, 2002. SFAS 142 changed the accounting for goodwill from an amortization approach to an impairment-only approach. Thus, amortization of goodwill that was not included as an allowable cost for rate-making purposes ceased upon SFAS 142's adoption.

Goodwill is to be tested for impairment at a reporting unit level at least annually. The impairment review consists of a comparison of the fair value of a reporting unit to its carrying amount. If the fair value of a reporting unit is less than its carrying amount, an impairment loss is recognized in operations. Prior to the adoption of SFAS 142, the Company amortized goodwill on a straight-line basis over 40 years. SFAS 142 required an initial impairment review of all goodwill within six months of the adoption date. Results of the initial impairment review were to be treated as a change in accounting principle in accordance with APB Opinion No. 20 "Accounting Changes."

As required by SFAS 142, amortization of goodwill relating to the acquisition of the Ohio operations ceased on January 1, 2002. In 2001, net income before cumulative effect of change in accounting principle and net income would have been $46.7 million and $47.8 million, respectively, had goodwill not been amortized and in 2000, net income would have been $56.4 million had goodwill not been amortized. The Company's goodwill is included in the Gas Utility Services operating segment. Initial impairment reviews to be performed within six months of adoption of SFAS 142 were completed and resulted in no impairment. The impairment test is performed at the beginning of each year. Following is a reconciliation of reported net income to the adjusted net income disclosed above for years ended December 31, 2001 and 2000:

In millions	2001	2000
Net Income, As Reported	$44.8	$55.9
Add: goodwill amortization - net of tax	3.0	0.5
Net Income, As Adjusted	$47.8	$56.4

H. 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.

SFAS 71
The Company's accounting policies give recognition to the rate-making and accounting practices of these agencies and to accounting principles generally accepted in the United States, including the provisions of SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Regulatory assets represent probable future revenues associated with certain incurred costs, which will be recovered from customers through the rate-making process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the rate-making process.

The Company assesses the recoverability of costs recognized as regulatory assets and the ability to continue to account for its activities based on the criteria set forth in SFAS 71. Based on current regulation, the Company believes such accounting is appropriate. If all or part of the Company's operations cease to meet the criteria of SFAS 71, 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.

Regulatory assets consist of the following:

In millions	At December 31, 2002	2001
Demand side management programs	$ 32.1	$ 31.7
Unamortized debt issue costs	19.5	21.2
Regulatory income tax asset	15.8	10.3
Other	7.8	4.6
Total regulatory assets	$ 75.2	$ 67.8

As of December 31, 2002, regulatory assets totaling $42.6 million are reflected in rates charged to customers, of which $17.2 million is earning a return. The remaining $32.6 million, which is not yet included in rates, represents primarily electric demand side management (DSM) costs incurred after 1993. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable. At December 31, 2002, the weighted average recovery period of regulatory assets, other than those arising from book - tax basis differences, included in rates is 16.0 years. Regulatory income tax assets are recovered as deferred tax assets and liabilities discussed in Note 4 become payable or receivable.

Refundable or Recoverable Gas Costs, Fuel for Electric Production & 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 typically contain a fuel adjustment clause that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel and the net energy cost of purchased power. Metered electric rates also allow recovery, through a quarterly rate adjustment mechanism, for the margin on electric sales lost due to the implementation of demand side management programs.

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 for electric generation is charged to operating expense when consumed.

I. Comprehensive Income

Comprehensive income is a measure of all changes in equity that result from the transactions or other economic events during the period from non-shareholder transactions. This information is reported in the Consolidated Statements of Common Shareholder's Equity. The principal transaction resulting in other comprehensive income relates to a minimum pension liability adjustment which is a loss of $3.8 million ($2.4 million after tax) in 2001. In 2002, all such liabilities were transferred to Vectren. The remaining component of accumulated other comprehensive income relates to a cash flow hedge discussed in Note 12.

J. 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.

K. Excise and Gross Receipts Taxes

Excise taxes and a portion of gross receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $32.4 million in 2002, $26.6 million in 2001, and $16.6 million in 2000. Excise and gross receipts taxes paid are recorded as a component of taxes other than income taxes.

L. Earnings Per Share
Earnings per share are not presented as VUHI's common stock is wholly owned by Vectren.

M. Other Significant Policies
Included elsewhere in these notes are significant accounting policies related to intercompany allocations and income taxes (Note 4) and derivatives (Note 12).

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

3. Restatement of Previously Reported Results

The Company identified adjustments that, in the aggregate, reduced previously reported 2001 earnings by approximately $10.6 million after tax and other adjustments, as described below, related to 2000 and prior periods. Adjustments were also made to previously reported 2002 quarterly results. In addition to adjustments affecting previously reported net income, other reclassifications were made to the previously reported 2001 and 2000 results to conform with the 2002 presentation.

Previously Reported 2001 and 2000 Net Income Adjustments

The Company determined that $11.6 million ($7.2 million after tax) of gas costs were improperly recorded as recoverable gas costs due from customers. The error related primarily to the accounting for natural gas inventory and resulted in an overstatement of 2001 earnings.

The Company also identified an accounting error related to certain employee benefit and other related costs that are routinely accumulated on the balance sheet and systematically cleared to operating expense and capital projects. Because of inadequate loading rates, these costs were not fully cleared to operating expense and capital projects in 2001. As a result, 2001 earnings were overstated by $5.6 million ($3.5 million after tax).

The accounting for certain wholesale power marketing contracts was modified to comply with SFAS 133, which became effective on January 1, 2001. The cumulative effect at adoption was decreased by $2.8 million after tax. This change was offset substantially by an increase in electric margins throughout 2001.

The Company identified reconciliation errors and other errors related to the recording of estimates that were not significant, either individually or in the aggregate. As a result of these additional items, 2001 earnings were reduced by $2.2 million ($1.4 million after tax). Originally reflected in 2001, the correction of the year 2000 overstatement of electric revenue totaling $2.4 million ($1.5 million after tax), now reflected in 2000 as discussed below, significantly offset these additional items.

The Company also determined that certain billings and collections had been improperly recorded in 2000, resulting in an understatement of gas revenue by $1.8 million ($1.1 million after tax) and an overstatement of electric revenue by $2.4 million ($1.5 million after tax). Other errors were identified that increased 2000 earnings by $0.8 million ($0.5 million after tax). The impact of the restatement of results for the year ended 2000 is an increase to net income of approximately $100,000.

Previously Reported 2002 Quarterly Net Income Adjustments

As previously reported, in the second quarter of 2002 the Company recorded $5.2 million ($3.2 million after tax) of carrying costs for DSM programs pursuant to existing IURC orders and based on an improved regulatory environment. During the audit of the three years ended December 31, 2002, management determined that the accrual of such carrying costs was more appropriate in periods prior to 2000 when DSM program expenditures were made. Therefore, such carrying costs originally reflected in 2002 quarterly results were reversed and reflected in common shareholder's equity as of January 1, 2000. In addition, the Company identified other adjustments that were not significant, either individually or in the aggregate that increased previously reported 2002 quarterly pre-tax and after tax earnings by approximately $1.8 million and $1.1 million after tax, respectively. The cumulative impact from of these adjustments reduced previously reported earnings for the nine months ended September 30, 2002 by approximately $2.1 million.

Beginning Retained Earnings Adjustments

In addition to the adjustment of DSM costs above, the Company identified other errors that were not significant, either individually or in the aggregate that relate to years prior to 2000. As a result of these additional items, beginning common shareholders' equity was reduced by $1.5 million. Accordingly, retained earnings as of January 1, 2000 reflects a cumulative net increase of $1.7 million.

Other Balance Sheet Adjustments

Certain reclassifications were made to reflect separate Company prepaid and accrued taxes that result in the consolidated tax position. This adjustment added approximately $26.6 million to receivables due from other Vectren companies and prepaid and other current assets with a corresponding increase in payables due to other Vectren companies, accrued liabilities, and deferred taxes as of December 31, 2001. The Company also reclassified all previously recorded goodwill not included in rates to goodwill on the balance sheet. This adjustment resulted in a $5.9 million decrease in other assets, a $3.0 million decrease in prepayments and other current assets and an $8.9 million increase in goodwill.

Transfer of Assets to VUHI

Effective January 1, 2003, Vectren transferred certain information technology systems and related assets and buildings from other entities within its consolidated group to VUHI. These assets primarily support the operations of VUHI's subsidiaries and VUHI's subsidiaries receive a charge for their use that is included in their other operating expenses. The transfer requires retroactive restatement of VUHI's consolidated financial statements for all periods presented under accounting rules governing combinations of entities under common control.

The years ended December 31, 2001 and 2000, have been restated for this asset transfer, and the year ended December 31, 2002 reflects that asset transfer. For the year ended December 31, 2002, operating income and net income attributable to the contributed assets were $8.5 million and $3.5 million, respectively. For the year ended December 31, 2002, operating income and net income attributable to VUHI's historical operations were $199.2 million and $93.6 million, respectively. As of December 31, 2002, total assets attributable to the contributed assets were $131.1 million, and total assets attributable to VUHI's historical operations were $2,439.3 million.

The Company has restated its financial statements to give effect to the matters discussed above. Following is a summary of the effects of the asset transfer and restatement of previously reported results of operations for 2001 and 2000. The effects of these events on 2001 quarterly results and on 2002 previously reported quarterly information, is discussed in Note 18. Note 18 is unaudited.

The effects on the income statement for the year ending December 31, 2001 follow:

		Adjustments for		
	As Reported	Asset Transfer	Restatement	As Restate
OPERATING REVENUES				
Gas utility	$ 1,031.5	$ -	$ (11.9)	$ 1,019.6
Electric utility	378.9	-	2.3	381.2
Other	-	0.2	-	0.2
Total operating revenues	1,410.4	0.2	(9.6)	1,401.0
OPERATING EXPENSES				
Cost of gas sold	708.2	-	0.7	708.9
Fuel for electric generation	74.4	-	-	74.4
Purchased electric energy	91.7	-	(4.8)	86.9
Other operating	234.7	(29.0)	6.4	212.1
Merger & integration costs	2.8	-	-	2.8
Restructuring costs	15.0	-	-	15.0
Depreciation & amortization	96.9	20.7	0.3	117.9
Taxes other than income taxes	51.3	0.4	(0.1)	51.6
Total operating expenses	1,275.0	(7.9)	2.5	1,269.6
OPERATING INCOME	135.4	8.1	(12.1)	131.4
OTHER INCOME				
Other - net	5.0	0.1	0.5	5.6
Equity in earnings of unconsolidated affiliates	-	-	(0.5)	(0.5
Total other income	5.0	0.1	-	5.1
Interest expense	70.1	0.6	-	70.7
INCOME BEFORE INCOME TAXES	70.3	7.6	(12.1)	65.8
Income taxes	22.7	2.9	(4.3)	21.3
Preferred dividend requirements of a subsidiary	0.8	-	-	0.8
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	46.8	4.7	(7.8)	43.7
Cumulative effect of change in accounting principle - net of tax	3.9	-	(2.8)	1.1

NET INCOME	$ 50.7	$ 4.7	$ (10.6)	$ 44.8

The effects on the income statement for the year ending December 31, 2000 follow:

		Adjustments for		
	As Reported	Asset Transfer	Restatement	As Restated
OPERATING REVENUES				
Gas utility	$ 818.8	$ -	$ 1.6	$ 820.4
Electric utility	336.4	-	(2.0)	334.4
Other	-	0.3	-	0.3
Total operating revenues	1,155.2	0.3	(0.4)	1,155.1
OPERATING EXPENSES				
Cost of gas sold	552.5	-	-	552.5
Fuel for electric generation	75.7	-	-	75.7
Purchased electric energy	36.4	-	-	36.4
Other operating	209.9	(28.4)	(0.9)	180.6
Merger & integration costs	32.7	-	-	32.7
Depreciation & amortization	82.4	22.2	-	104.6
Taxes other than income taxes	36.2	0.3	-	36.5
Total operating expenses	1,025.8	(5.9)	(0.9)	1,019.0
OPERATING INCOME	129.4	6.2	0.5	136.1
Other income - net	5.0	(0.4)	(0.3)	4.3
Interest expense	46.1	0.3	-	46.4
INCOME BEFORE INCOME TAXES	88.3	5.5	0.2	94.0
Income taxes	34.9	2.1	0.1	37.1
Preferred dividend requirements of subsidiary	1.0	-	-	1.0
NET INCOME	$ 52.4	$ 3.4	$ 0.1	$ 55.9

The effects on the balance sheet as of December 31, 2001 follow:

	Adjustments for
ASSETS	

	As Reported	Asset Transfer	Restatement	As Restat
Current Assets				
Cash & cash equivalents	$ 7.2	$ 0.2	$ (2.2)	$ 5
Accounts receivable-less reserves	125.3	-	(2.2)	123
Receivables due from other Vectren companies	26.6	-	59.7	86
Accrued unbilled revenues	78.3	-	(1.2)	77
Inventories	55.3	-	(0.5)	54
Recoverable fuel & natural gas costs	76.5	-	(6.3)	70
Prepayments & other current assets	127.4	-	(44.6)	82
Total current assets	496.6	0.2	2.7	499
Utility Plant				
Original cost	2,903.2	-	2.9	2,906
Less: accumulated depreciation & amortization	1,308.2	-	-	1,308
Net utility plant	1,595.0	-	2.9	1,597
Investments in unconsolidated affiliates	4.0	-	(0.5)	3
Other investments	12.2	7.8	-	20
Non-utility property-net	6.3	78.7	-	85
Goodwill-net	193.1	-	8.4	201
Regulatory assets	61.4	-	6.4	67
Other assets	22.8	-	(8.7)	14
TOTAL ASSETS	$2,391.4	$ 86.7	$ 11.2	$ 2,489
LIABILITIES & SHAREHOLDER'S EQUITY				
Current Liabilities				
Accounts payable	$ 79.0	$ -	$ 0.4	$ 79
Accounts payable to affiliated companies	36.5	-	0.9	37
Payables due to other Vectren companies	11.5	22.4	17.7	51
Accrued liabilities	97.5	0.5	(2.8)	95
Short-term borrowings due to other Vectren companies	-	29.0	-	29
Short-term borrowings	274.2	-	-	274
Long-term debt subject to tender	11.5	-	-	11
Current maturities of long-term debt	1.3	-	-	1
Total current liabilities	511.5	51.9	16.2	579
Long-Term Debt-Net of Current Maturities & Debt Subject to Tender	900.9	-	-	900
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	171.8	-	4.7	176
Deferred credits & other liabilities	93.7	-	(0.8)	92
Total deferred credits & other liabilities	265.5	-	3.9	269
Cumulative, Redeemable Preferred Stock of a Subsidiary	0.5	-	-	0

Common shareholder's equity				
Common stock (no par value)	385.7	-	-	385
Retained earnings	329.0	34.8	(8.8)	355
Accumulated other comprehensive loss	(1.7)	-	(0.1)	(1
Total common shareholder's equity	713.0	34.8	(8.9)	738
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$2,391.4	$ 86.7	$ 11.2	$ 2,489

4. Transactions with Other Vectren Companies

Support Services and Purchases

Vectren and certain subsidiaries of Vectren provided corporate and general and administrative services to the Company including legal, finance, tax, risk management, human resources, which includes charges for restricted stock compensation and for pension and other postretirement benefits not directly charged to subsidiaries. These costs have been allocated using various allocators, primarily number of employees, number of customers and/or revenues. Allocations are based on cost. VUHI received corporate allocations totaling $41.4 million, $49.4 million, and $36.8 million for the years ended December 31, 2002, 2001, and 2000, respectively.

Vectren Fuels, Inc., a wholly owned subsidiary of Vectren, owns and operates coal mines from which SIGECO purchases fuel used for electric generation. Amounts paid for such purchases for the years ended December 31, 2002, 2001, and 2000, totaled $62.1 million, $58.4 million, and $25.7 million, respectively.

Retirement Plans and Other Postretirement Benefits

Vectren has multiple defined benefit pension plans and postretirement plans that require accounting as described in SFAS No. 87 "Employers' Accounting for Pensions and SFAS No. 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions," respectively. Subsequent to the merger forming Vectren, an allocation of expense is determined by Vectren's actuaries, comprised of only service cost and interest on that service cost, by subsidiary based on headcount at each measurement date. These costs are directly charged to individual subsidiaries. Other components of costs (such interest cost from prior service and asset returns) are charged to individual subsidiaries through the corporate allocation process discussed above. Plan assets nor the FAS 87/106 liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. Further, Vectren satisfies the future funding requirements of plans and the payment of benefits from general corporate assets. This allocation methodology is consistent with "multiemployer" benefit accounting as described in SFAS 87 and 106.

For the years ended December 31, 2002 and 2001 pension expense totaling $5.5 million and $5.1 million, respectively, were directly charged by Vectren to the Company. For the years ended December 31, 2002 and 2001other benefit expenses totaling $1.0 million in both years were directly charged by Vectren to the Company. In 2000, the Company recognized $8.8 million in charges for participation in Vectren benefit plans. As of December 31, 2002 and 2001, $51.8 million and $53.3 million is included in other non-current liabilities and represents expense directly charged to the Company that is yet to be funded to Vectren, and $3.5 million and $4.8 million is included in other assets for amounts funded in advance to Vectren.

Cash Management and Borrowing Arrangements

The Company participates in a centralized cash management program with Vectren, other wholly owned subsidiaries, and banks which permits funding of checks as they are presented.

Vectren's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of VUHI's $350.0 million commercial paper program, of which $239.1 million is outstanding at December 31, 2002 and VUHI's $350.0 million unsecured senior notes outstanding at December 31, 2002. VUHI has no independent assets or operations, the guarantees are full and unconditional and joint and several, and VUHI has no subsidiaries other than the subsidiary guarantors.

Stock-Based Incentive Plans

VUHI does not have stock-based compensation plans separate from Vectren. An insignificant number of VUHI's employees participate in Vectren's stock-based compensation plans.

Income Taxes

Vectren and subsidiary companies file a consolidated federal income tax return. For financial reporting purposes, VUHI's current and deferred tax expense is computed on a separate company basis.

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

	Year Ended December 31,		
In millions	2002	2001	2000
Current:			
Federal	$ 62.5	$ 32.2	$ 21.4
State	7.7	4.0	2.8
Total current taxes	70.2	36.2	24.2
Deferred:			
Federal	(16.2)	(12.0)	13.8
State	(4.9)	(0.6)	1.5
Total deferred taxes	(21.1)	(12.6)	15.3
Amortization of investment tax credits	(2.3)	(2.3)	(2.4)
Total income tax expense	$ 46.8	$ 21.3	$ 37.1

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

	Year Ended December 31,		
	2002	2001	2000
Statutory rate	35.0 %	35.0 %	35.0 %
State and local taxes-net of federal benefit	1.3	3.3	3.6
Nondeductible merger costs	-	-	4.8
Amortization of investment tax credit	(1.7)	(4.0)	(2.7)
All other-net	(2.3)	(2.2)	(0.7)
Effective tax rate	32.3 %	32.1 %	40.0 %

The liability method of accounting is used for income taxes under which deferred income taxes are recognized to reflect the tax effect of temporary differences between the book and tax bases of assets and liabilities at currently enacted income tax rates. Significant components of the net deferred tax liability follow:

	At December 31,	
In millions	2002	2001
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$ 189.8	$ 197.1
Regulatory assets recoverable through future rates	37.5	33.5
Regulatory liabilities to be settled through future rates	(21.7)	(23.2)
Employee benefit obligations	(30.2)	(24.3)
Other - net	(3.1)	(6.6)
Net noncurrent deferred tax liability	172.3	176.5
Current deferred tax liabilities (assets):		
Deferred fuel costs-net	7.7	21.1
LIFO inventory	-	(2.0)
Net current deferred tax liability	7.7	19.1
Net deferred tax liability	$ 180.0	$ 195.6

At December 31, 2002 and 2001, investment tax credits totaling $18.6 million and $20.9 million, respectively, are included in deferred credits and other liabilities. These investment tax credits are amortized over the lives of the related investments. The Company has no tax credit carryforwards at December 31, 2002. Alternative Minimum Tax credit carryforwards of approximately $5.2 million were utilized in 2001.

5. Transactions with Vectren Affiliates

ProLiance Energy, LLC

ProLiance Energy, LLC (ProLiance), a nonregulated energy marketing affiliate of Vectren and Citizens Gas and Coke Utility (Citizens Gas), provides natural gas and related services to Indiana Gas, the Ohio operations, Citizens Gas and others. ProLiance also began providing service to SIGECO and Vectren Retail, LLC (the Company's retail gas marketer) in 2002. ProLiance's primary business is optimizing the gas portfolios of utilities and providing services to large end use customers. Vectren continues to account for its investment in ProLiance using the equity method of accounting.

Regulatory Matters

The sale of gas and provision of other services to Indiana Gas and SIGECO by ProLiance is subject to regulatory review through the quarterly gas cost adjustment (GCA) process administered by the IURC. The sale of gas and provision of other services to the Ohio operations by ProLiance is subject to regulatory review through the quarterly gas cost recovery (GCR) and audit process administered by the PUCO.

Specific to the sale of gas and provision of other services to Indiana Gas by ProLiance, on September 12, 1997, the IURC issued a decision finding the gas supply and portfolio administration agreements between ProLiance and Indiana Gas and ProLiance and Citizens Gas to be consistent with the public interest and that ProLiance is not subject to regulation by the IURC as a public utility. However, with respect to the pricing of gas commodity purchased from ProLiance, the price paid by ProLiance to the utilities for the prospect of using pipeline entitlements if and when they are not required to serve the utilities' firm customers, and the pricing of fees paid by the utilities to ProLiance for portfolio administration services, the IURC concluded that additional review in the GCA process would be appropriate and directed that these matters be considered further in a consolidated GCA proceeding involving Indiana Gas and Citizens Gas.

On June 4, 2002, Indiana Gas and Citizens Gas, together with the OUCC and other consumer parties, entered into and filed with the IURC a settlement setting forth the terms for resolution of all pending regulatory issues related to ProLiance, including the three pricing issues. On July 23, 2002, the IURC approved the settlement filed by the parties. The GCA proceeding has been concluded and new supply agreements between Indiana Gas, SIGECO, Citizens Gas, and ProLiance have been approved and extended through March 31, 2007. ProLiance will also have the opportunity, if it so elects, to participate in a "request for proposal" process for service to the utilities after March 31, 2007.

For past services provided to Indiana Gas by ProLiance, Indiana Gas made refunds to retail customers pursuant to the settlement totaling $6.4 million in the fourth quarter of 2002. A subsidiary of Vectren's nonregulated operations has indemnified Indiana Gas for the amount of the refund as well as any other amounts incurred as a result of the settlement. Accordingly, the refund had no effect on operating margin or net income.

Transactions with ProLiance

Purchases from ProLiance for resale and for injections into storage for the years ended December 31, 2002, 2001, and 2000 totaled $542.5 million, $610.6 million, and $478.9 million, respectively. Amounts owed to ProLiance at December 31, 2002 and 2001 for those purchases were $83.7 million and $36.1 million, respectively, and are included in accounts payable to affiliated companies in the Consolidated Balance Sheets. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

Other Affiliate Transactions

The Company has ownership interests in other affiliated companies accounted for using the equity method of accounting that provide materials management, underground construction and repair, facilities locating, and meter reading services to the Company. For the years ended December 31, 2002, 2001, and 2000, fees for these services and construction-related expenditures totaled $38.3 million, $30.4 million, and $6.9 million, respectively. Amounts charged by these affiliates are market based. Amounts owed to unconsolidated affiliates other than ProLiance totaled $1.8 million and $1.3 million at December 31, 2002 and 2001, respectively, and are included in accounts payable to affiliated companies in the Consolidated Balance Sheets.

6. Borrowing Arrangements

Long-Term Debt

Senior unsecured obligations and first mortgage bonds outstanding and classified as long-term by subsidiary follow:

	At December 31,	
In millions	2002	2001
VUHI		
Fixed Rate Senior Unsecured Notes		
2011, 6.625%	$ 250.0	$ 250.0
2031, 7.25%	100.0	100.0

Total VUHI	350.0	350.0
SIGECO		
First Mortgage Bonds		
Fixed Rate:		
2003, Series B, 6.25%, tax exempt	1.0	1.0
2016, 1986 Series, 8.875%	13.0	13.0
2023, Series, 7.60%	45.0	45.0
2023, Series B, 6.00%, tax exempt	22.8	22.8
2025, 1993 Series, 7.625%	20.0	20.0
2029, 1999 Senior Notes, 6.72%	80.0	80.0
Adjustable Rate:		
2015, Pollution Control Series A, presently 4.30%, tax exempt, next rate adjustment: 2004	10.0	10.0
2025, Pollution Control Series A, presently 4.75%, tax exempt, next rate adjustment: 2006	31.5	31.5
2024, Environmental Improvement Series A, tax exempt, adjusts every 35 days, weighted average for year: 1.80%	22.5	22.5
Total First Mortgage Bonds	245.8	245.8
Adjustable Rate Senior Unsecured Bonds		
2020, Pollution Control Series B, presently 4.40%, tax exempt, next rate adjustment: 2003	4.6	4.6
2030, Pollution Control Series B, presently 4.40%, tax exempt, next rate adjustment: 2003	22.0	22.0
2030, Pollution Control Series C, presently 5.00%, tax exempt, next rate adjustment: 2006	22.2	22.2
Total Adjustable Rate Senior Unsecured Bonds	48.8	48.8
Total SIGECO	294.6	294.6

	At December 31,	
In millions	2002	2001
Indiana Gas		
Fixed Rate Senior Unsecured Notes		
2003, Series F, 5.75%	15.0	15.0
2004, Series F, 6.36%	15.0	15.0
2007, Series E, 6.54%	6.5	6.5
2013, Series E, 6.69%	5.0	5.0
2015, Series E, 7.15%	5.0	5.0
2015, Insured Quarterly, 7.15%	20.0	20.0
2015, Series E, 6.69%	5.0	5.0
2015, Series E, 6.69%	10.0	10.0
2021, Private Placement, 9.375%, $1.3 due annually in 2002	23.8	25.0
2025, Series E, 6.31%	-	5.0
2025, Series E, 6.53%	10.0	10.0
2027, Series E, 6.42%	5.0	5.0
2027, Series E, 6.68%	3.5	3.5
2027, Series F, 6.34%	20.0	20.0
2028, Series F, 6.75%	13.6	13.8
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

2030, Insured Quarterly, 7.45%	49.9	50.0
Total Indiana Gas	267.3	273.8
Total long-term debt outstanding	911.9	918.4
Less: Current maturities of long-term debt	39.8	1.3
Debt subject to tender	26.6	11.5
Unamortized debt premium & discount - net	4.3	4.7
Total long-term debt-net	$ 841.2	$ 900.9

VUHI

In September 2001, VUHI filed a shelf registration statement with the Securities and Exchange Commission for $350.0 million aggregate principal amount of unsecured senior notes. In October 2001, VUHI issued senior unsecured notes with an aggregate principal amount of $100.0 million and an interest rate of 7.25% (the October Notes), and in December 2001, issued the remaining aggregate principal amount of $250.0 million at an interest rate of 6.625% (the December Notes). The December Notes were priced at 99.302% to yield 6.69% to maturity.

These issues have no sinking fund requirements, and interest payments are due quarterly for the October Notes and semi-annually for the December Notes. The October Notes are due October 2031, but may be called by the Company, in whole or in part, at any time after October 2006 at 100% of the principal amount plus any accrued interest thereon. The December Notes are due December 2011, but may be called by the Company, in whole or in part, at any time for an amount equal to accrued and unpaid interest, plus the greater of 100% of the principal amount or the sum of the present values of the remaining scheduled payments of principal and interest, discounted to the redemption date on a semi-annual basis at the Treasury Rate, as defined in the indenture, plus 25 basis points.

The net proceeds from the sale of the senior notes and settlement of the hedging arrangements (see Note 12) totaled $344.0 million.

Indiana Gas

In December 2000, $20.0 million of 15-Year Insured Quarterly (IQ) Notes at an interest rate of 7.15% and $50.0 million of 30-Year IQ Notes at an interest rate of 7.45% were issued. Indiana Gas may call the 15-Year IQ Notes, in whole or in part, from time to time on or after December 15, 2004 and has the option to redeem the 30-Year IQ Notes in whole or in part, from time to time on or after December 15, 2005. The IQ notes have no sinking fund requirements. The net proceeds totaled $67.9 million. Both the quarterly interest payments and the principal amount of the IQ Notes are insured by Ambac Assurance Corporation.

Long-Term Debt Put & Call Provisions

On January 15, 2003, the Company called the remaining $23.8 million of Indiana Gas' 9.375% private placement notes originally due in 2021. Since the proceeds to repay the notes were generated from short-term borrowings, these notes are classified in current maturities of long-term debt at December 31, 2002.

Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. Other than those described below related to ratings triggers, the put or call provisions are not triggered by specific events, but are based upon dates stated in the note agreements, such as when notes are re-marketed. Debt subject to tender during the years following 2002 (in millions) is $26.6 in 2003, $13.5 in 2004, $10.0 in 2005, $53.7 in 2006, $20.0 in 2007, and $120.0 thereafter. Debt that may be put to the Company within one year is classified as debt subject to tender in current liabilities.

Long-Term Debt Sinking Fund Requirements & Maturities

The annual sinking fund requirement of SIGECO's first mortgage bonds is 1% 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 2002 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2002 is excluded from current liabilities in the Consolidated Balance Sheets. At December 31, 2002, $342.8 million of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture.

Consolidated maturities and sinking fund requirements on long-term debt, including debt to be called, during the five years following 2002 (in millions) are $39.8 in 2003, $15.0 in 2004, zero in 2005, zero in 2006, and $6.5 in 2007.

Short-Term Borrowings

At December 31, 2002, the Company has $330.0 million of short-term borrowing capacity, of which approximately $90.9 million is available. Subsequent to December 31, 2002, the Company increased its capacity $145.0 million to $475.0 million. See the table below for interest rates and outstanding balances.

	Year ended December 31,		
In millions	2002	2001	2000
Weighted average commercial paper and bank loans outstanding during the year	$ 155.7	$ 356.1	$ 190.0
Weighted average interest rates during the year			
Bank loans	2.61%	4.39%	6.62%
Commercial paper	2.02%	5.77%	6.60%

	At December 31,	
In millions	2002	2001
Commercial paper	$ 239.1	$ 273.3
Bank loans	-	0.9
Total short-term borrowings	$ 239.1	$ 274.2

Prior to the asset transfer discussed in Note 3, the operations integrated with VUHI relied on the borrowing arrangements of Vectren Capital Corp, a wholly owned subsidiary of Vectren, for its working capital needs. Borrowings outstanding from Vectren Capital Corp at December 31, 2002 and 2001 were $86.9 million and $29.0 million, respectively. Interest expense incurred on these borrowing arrangements for the years ended December 31, 2002, 2001, and 2000 totaled $3.0 million, $0.6 million, and $0.2 million, respectively.

Debt Guarantees

VUHI's currently outstanding long-term and short-term debt is guaranteed by Indiana Gas, SIGECO, and VEDO. The guarantees are full and unconditional and joint and several, and VUHI has no subsidiaries other than the subsidiary guarantors. VUHI's long-term and short-term debt outstanding at December 31, 2002 totaled $350.0 million and $239.1 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. As of December 31, 2002, the Company was in compliance with all financial covenants.

7. Cumulative Preferred Stock of a Subsidiary

Redemption of Preferred Stock of a Subsidiary
Nonredeemable preferred stock of a subsidiary containing call options was redeemed during September 2001 for a total redemption price of $9.8 million. The 4.80%, $100 par value preferred stock was redeemed at its stated call price of $110 per share, plus accrued and unpaid dividends totaling $1.35 per share. The 4.75%, $100 par value preferred stock was redeemed at its stated call price of $101 per share, plus accrued and unpaid dividends totaling $0.97 per share. Prior to the redemptions, there were 85,519 shares of the 4.80% Series outstanding and 3,000 shares of the 4.75% Series outstanding.

In September 2001, the 6.50%, $100 par value of redeemable preferred stock of a subsidiary was redeemed for a total redemption price of $7.9 million at $104.23 per share, plus $0.73 per share in accrued and unpaid dividends. Prior to the redemption, there were 75,000 shares outstanding.

As both series of preferred stock redeemed was that of a subsidiary, the loss on redemption of $1.2 million in 2001 is reflected in retained earnings.

Redeemable, Special
This series of redeemable preferred stock has a dividend rate of 8.50% and in the event of involuntary liquidation the amount payable is $100 per share, plus accrued dividends. This series may be redeemed at $100 per share, plus accrued dividends on any of its dividend payment dates and is also callable at the Company's option at a rate of 1,160 shares per year. As of December 31, 2002 and 2001, there were 3,437 shares and 4,597 shares outstanding, respectively.

8. Common Shareholder's Equity

In February 2001, the Company received $129.4 million from an equity contribution by Vectren. Vectren funded the contribution with the proceeds from an offering of its common stock. In December 2001, Vectren made an additional equity contribution of $35.0 million with proceeds received from dividends paid by Vectren's nonregulated operations.

9. Commitments & Contingencies

Commitments
Firm commitments to purchase natural gas for years following December 31, 2002 totaled (in millions) $89.5 in 2003, $21.3 in 2004, and $3.6 million in 2005.

Legal Proceedings
The Company is party to various legal proceedings arising in the normal course of business. In the opinion of management, there are no legal proceedings pending against the Company that are likely to have a material adverse effect on its financial position or results of operations. See Note 10 regarding the Clean Air Act.

10. Environmental Matters

Clean Air Act

NOx SIP Call Matter
The Clean Air Act (the Act) requires each state to adopt a State Implementation Plan (SIP) to attain and maintain National Ambient Air Quality Standards (NAAQS) for a number of pollutants, including ozone. If the USEPA finds a state's SIP inadequate to achieve the NAAQS, the USEPA can call upon the state to revise its SIP (a SIP Call).

In October 1998, the USEPA issued a final rule "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment

Group Region for Purposes of Reducing Regional Transport of Ozone," (63 Fed. Reg. 57355). This ruling found that the SIP's of certain states, including Indiana, were substantially inadequate since they allowed for nitrogen oxide (NOx) emissions in amounts that contributed to non-attainment with the ozone NAAQS in downwind states. The USEPA required each state to revise its SIP to provide for further NOx emission reductions. The NOx emissions budget, as stipulated in the USEPA's final ruling, requires a 31% reduction in total NOx emissions from Indiana.

In June 2001, the Indiana Air Pollution Control Board adopted final rules to achieve the NOx emission reductions required by the NOx SIP Call. Indiana's SIP requires the Company to lower its system-wide NOx emissions to .14 lbs./MMBTU by May 31, 2004 (the compliance date). This is a 65% reduction from emission levels existing in 1999 and 1998.

The Company has initiated steps toward compliance with the revised regulations. These steps include installing Selective Catalytic Reduction (SCR) systems at Culley Generating Station Unit 3 (Culley), Warrick Generating Station Unit 4, and A.B. Brown Generating Station Units 1 and 2. SCR systems reduce flue gas NOx emissions to atmospheric nitrogen and water using ammonia in a chemical reaction. This technology is known to be the most effective method of reducing NOx emissions where high removal efficiencies are required.

On August 28, 2001, the IURC issued an order that (1) approved the Company's proposed project to achieve environmental compliance by investing in clean coal technology, (2) approved the Company's initial cost estimate of $198 million for the construction, subject to periodic review of the actual costs incurred, and (3) approved a mechanism whereby, prior to an electric base rate case, the Company may recover through a rider that is updated every six months a return on its capital costs for the project, at its overall cost of capital, including a return on equity. The first rider adjustment for ongoing cost recovery was approved by the IURC on February 6, 2002. Based on the level of system-wide emissions reductions required and the control technology utilized to achieve the reductions, the current estimated clean coal technology construction cost ranges from $240 million to $250 million and is expected to be expended during the 2001-2006 period. Through December 31, 2002, $70.0 million has been expended.

On June 5, 2002, the Company filed a new proceeding to update the NOx project cost and to obtain approval of a second rider authorizing ongoing recovery of depreciation and operating costs related to the clean coal technology. After the equipment is installed and operational, related annual operating expenses, including depreciation expense, are estimated to be between $24 million and $27 million. Such expenses would commence in 2004 when the technology becomes operational. On January 3, 2003, the IURC approved a settlement that authorizes total capital cost investment for this project up to $244 million (excluding AFUDC) and recovery on those capital costs, as well as the recovery of future operating costs, including depreciation and purchased emission allowances, through a rider mechanism. The settlement establishes a fixed return of 8 percent on the capital investment, which approximates the return authorized in the Company's last electric rate case in 1995.

The Company expects to achieve timely compliance as a result of the project. Construction of the first SCR at Culley is nearing completion on schedule, and installation of SCR technology as planned is expected to reduce the Company's overall NOx emissions to levels compliant with Indiana's NOx emissions budget allotted by the USEPA. Therefore, the Company has recorded no accrual for potential penalties that may result from noncompliance.

Culley Generating Station Litigation

In the late 1990's, the USEPA initiated an investigation under Section 114 of the Act of SIGECO's coal-fired electric generating units in commercial operation by 1977 to determine compliance with environmental permitting requirements related to repairs, maintenance, modifications, and operations changes. The focus of the investigation was to determine whether new source review permitting requirements were triggered by such plant modifications, and whether the best available control technology was, or should have been used. Numerous electric utilities were, and are currently, being investigated by the USEPA under an industry-wide review for compliance. In July 1999, SIGECO received a letter from the Office of Enforcement and Compliance Assurance of the USEPA discussing the industry-wide investigation, vaguely referring to an investigation of SIGECO and inviting SIGECO to participate in a discussion of the issues. No specifics were noted; furthermore, the letter stated that the communication was not intended to serve as a notice of violation. Subsequent meetings were conducted in September and October 1999 with the USEPA and targeted utilities, including SIGECO, regarding potential remedies to the USEPA's general allegations.

On November 3, 1999, the USEPA filed a lawsuit against seven utilities, including SIGECO. SIGECO's suit is pending in the U.S. District Court for the Southern District of Indiana. The USEPA alleges that, beginning in 1992, SIGECO violated the Act by (1) making modifications to its Culley Generating Station in Yankeetown, Indiana without obtaining required permits (2) making major modifications to the Culley Generating Station without installing the best available emission control technology and (3) failing to notify the USEPA of the modifications. In addition, the lawsuit alleges that the modifications to the Culley Generating Station required SIGECO to begin complying with federal new source performance standards at its Culley Unit 3.

SIGECO believes it performed only maintenance, repair, and replacement activities at the Culley Generating Station, as allowed under the Act. Because proper maintenance does not require permits, application of the best available control technology, notice to the USEPA, or compliance with new source performance standards, SIGECO believes that the lawsuit is without merit, and intends to vigorously defend itself. Since the filing of this lawsuit, the USEPA has voluntarily dismissed a majority of the claims brought in its original complaint. In its original complaint, USEPA alleged significant emissions increases of three pollutants for each of four maintenance projects. Currently, USEPA is alleging only significant emission increases of a single pollutant at three of the four maintenance projects cited in the original complaint.

The lawsuit seeks fines against SIGECO in the amount of $27,500 per day per violation. However, on July 29, 2002, the Court ruled that USEPA could not seek civil penalties for two of the three remaining projects at issue in the litigation, significantly reducing potential civil penalty exposure. The lawsuit also seeks a court order requiring SIGECO to install the best available emissions technology at the Culley Generating Station. If the USEPA were successful in obtaining an order, SIGECO estimates that in response it could incur capital costs of approximately $20 million to $40 million to comply with the order. Trial is currently set to begin July 14, 2003.

The USEPA has also issued an administrative notice of violation to SIGECO making the same allegations, but alleging that violations began in 1977.

While it is possible that SIGECO could be subjected to criminal penalties if the Culley Generating Station continues to operate without complying with the permitting requirements of new source review and the allegations are determined by a court to be valid, SIGECO believes such penalties are unlikely as the USEPA and the electric utility industry have a bonafide dispute over the proper interpretation of the Act. Accordingly, the Company has recorded no accrual and the plant continues to operate while the matter is being decided.

Information Request
On January 23, 2001, SIGECO received an information request from the USEPA under Section 114 of the Act for historical operational information on the Warrick and A.B. Brown generating stations. SIGECO has provided all information requested,

and no further action has occurred.

Manufactured Gas Plants

In the past, Indiana Gas and others operated facilities for the manufacture of gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under currently applicable environmental laws and regulations, Indiana Gas and others may now be required to take remedial action if certain byproducts are found above the regulatory thresholds at these sites.

Indiana Gas has identified the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites for which it may have some remedial responsibility. Indiana Gas has completed a remedial investigation/feasibility study (RI/FS) 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. Although Indiana Gas has not begun an RI/FS at additional sites, Indiana Gas has submitted several of the sites to the IDEM's Voluntary Remediation Program and is currently conducting some level of remedial activities including groundwater monitoring at certain sites where deemed appropriate and will continue remedial activities at the sites as appropriate and necessary.

In conjunction with data compiled by environmental consultants, Indiana Gas 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, Indiana Gas has recorded costs that it reasonably expects to incur totaling approximately $20.4 million.

The estimated accrued costs are limited to Indiana Gas' proportionate share of the remediation efforts. Indiana Gas has arrangements in place for 19 of the 26 sites with other potentially responsible parties (PRP), which serve to limit Indiana Gas' share of response costs at these 19 sites to between 20% and 50%.

With respect to insurance coverage, Indiana Gas has received and recorded settlements from all known insurance carriers in an aggregate amount approximating $20.4 million.

Environmental matters related to manufactured gas plants have had no material impact on earnings since costs recorded to date approximate PRP and insurance settlement recoveries. While Indiana Gas has recorded all costs which it presently expects to incur in connection with activities at these sites, it is possible that future events may require some level of additional remedial activities which are not presently foreseen.

In October 2002, the Company received a formal information request letter from the IDEM regarding five manufactured gas plants owned and/or operated by SIGECO and not currently enrolled the IDEM's Voluntary Remediation Program. In response SIGECO submitted to the IDEM the results of preliminary site investigations conducted in the mid-1990's. These site investigations confirmed that based upon the conditions known at the time, the sites posed no risk to human health or the environment. Follow up reviews have recently been initiated by the Company to confirm that the sites continue to pose no such risk.

11. Rate & Regulatory Matters

Gas Costs Proceedings

Commodity prices for natural gas purchases were significantly higher during the 2000 - 2001 heating season, primarily due to colder temperatures, increased demand and tighter supplies. Subject to compliance with applicable state laws, Vectren's utility subsidiaries are allowed full recovery of such changes in purchased gas costs from their retail customers through commission-approved gas cost adjustment mechanisms.

In March 2001, Indiana Gas and SIGECO reached agreement with the OUCC and the Citizens Action Coalition of Indiana, Inc. (CAC) regarding the matters raised by an IURC Order that disallowed $3.8 million of Indiana Gas' gas procurement costs for the 2000 - 2001 heating season which was recognized during the year ended December 31, 2000. As part of the agreement, the companies agreed to contribute an additional $1.7 million to assist qualified low income gas customers, and Indiana Gas agreed to credit $3.3 million of the $3.8 million disallowed amount to its customers' April 2001 utility bills in exchange for both the OUCC and the CAC dropping their appeals of the IURC Order. In April 2001, the IURC issued an order approving the settlement. Substantially all of the financial assistance for low income gas customers was distributed in 2001.

Purchased Power Costs

As a result of an appeal of a generic order issued by the IURC in August 1999 regarding guidelines for the recovery of purchased power costs, SIGECO entered into a settlement agreement with the OUCC that provides certain terms with respect to the recoverability of such costs. The settlement, originally approved by the IURC in August 2000, has been extended by agreement through March 2003, and discussions regarding further extension of the settlement term are ongoing. Under the settlement, SIGECO can recover the entire cost of purchased power up to an established benchmark, and during forced outages, SIGECO will bear a limited share of its purchased power costs regardless of the market costs at that time. Based on this agreement, SIGECO believes it has limited its exposure to unrecoverable purchased power costs.

12. Risk Management, Derivatives, & Other Financial Instruments

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 to mitigate risk.

The Company also executes derivative contracts in the normal course of operations while buying and selling commodities and other fungible goods to be used in operations and while optimizing generation assets. The Company does not execute derivative contracts for speculative or trading purposes.

Commodity Price Risk

The Company's regulated operations have limited exposure to commodity price risk for purchases and sales of natural gas and electricity for retail customers due to current Indiana and Ohio regulations, which subject to compliance with those regulations, allow for recovery of such purchases through natural gas and fuel cost adjustment mechanisms.

Electric sales and purchases in the wholesale power market and other commodity-related operations are exposed to commodity price risk associated with fluctuating electric power and other commodity prices. Other commodity operations include sales of electricity to certain municipalities and large industrial customers.

The Company's non-firm wholesale power marketing operations manage the utilization of its available electric generating capacity by entering into forward and option contracts that commit the Company to purchase and sell electricity in the future. Commodity price risk results from forward positions that commit the Company to deliver electricity. The Company mitigates price risk exposure with planned unutilized generation capability and offsetting forward purchase contracts.

The Company's other commodity-related operations involve the purchase and sale of commodities, including electricity, to meet customer demands and operational needs. These operations also enter into forward contracts that commit the Company to purchase and sell commodities in the future. Price risk from forward positions that commit the Company to deliver commodities is mitigated using insurance contracts and offsetting forward purchase contracts.

Open positions in terms of price, volume, and specified delivery points may occur and are managed using methods described above and frequent management reporting.

Interest Rate Risk

The Company is exposed to interest rate risk associated with its adjustable rate borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on operations. The Company tries to limit the amount of adjustable rate borrowing arrangements exposed to short-term interest rate volatility to a maximum of 25% of total debt. However, there are times when this targeted level of interest rate exposure may be exceeded. To manage this exposure, the Company may periodically use derivative financial instruments to reduce earnings fluctuations caused by interest rate volatility.

Other Risks

By using forward purchase contracts and derivative financial instruments to manage risk, the Company exposes itself 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 a diversified base of 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.

Although the Company's regulated operations are exposed to limited commodity price risk, volatile natural gas prices can result in higher working capital requirements; increased expenses including unrecoverable interest costs, uncollectible accounts expense, and unaccounted for gas; and some level of price sensitive reduction in volumes sold.

Accounting for Derivatives & Other Contracts

When a derivative contract that is entered into in the normal course of operations is probable of physical settlement, that contract is designated and documented as a normal purchase or normal sale and is exempted from mark-to-market accounting. Otherwise, derivative 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. Unless the contract is a cash flow hedge that qualifies for hedge accounting treatment or is subject to SFAS 71, that contract is marked to market through earnings. When hedge accounting is appropriate, the Company assesses and documents hedging relationships between its financial instruments, including commodity contracts and interest rate swaps, and underlying risks as well as the investment's 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. The ineffective portion of hedging arrangements is marked to market through earnings. Contracts affected by SFAS 71 are marked to market as a regulatory asset or liability. Market value is determined using quoted market prices from independent sources.

Non-Firm Wholesale Power Marketing Contracts

Periodically, generation capacity is in excess of that needed to serve retail and firm wholesale customers. The Company markets this unutilized capacity to optimize the return on its owned generation assets. The contracts entered into are primarily short-term purchase and sale contracts that expose the Company to limited market risk and are settled both financially and physically. These operations do not meet the definition of energy trading activities based upon the provisions in EITF Issue 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10).

Asset optimization sale contracts are reflected in electric utility revenues, and purchase contracts are reflected in purchased electric energy. Contracts with counter-parties subject to master netting arrangements are presented net in the Consolidated Balance Sheets. Subsequent to the adoption of SFAS 133 as described below, certain non-firm power marketing contracts that are periodically financially settled are recorded at market value. Changes in market value, which is a function of the normal decline in market value as earnings are realized and the fluctuation in market value resulting from price volatility, are recorded in purchased electric energy.

Power marketing contracts recorded at market value at December 31, 2002 totaled $3.5 million of prepayments and other current assets and $4.2 million of accrued liabilities, compared to $6.1 million of prepayments and other current assets and $2.8 million of accrued liabilities at December 31, 2001. The change in the net value of these contracts includes an unrealized loss of $3.6 million in 2002 and an unrealized gain of $1.5 million in 2001, respectively. Including these unrealized changes in market value, overall margin (revenue net of purchased power) from non-firm wholesale power marketing operations for the years ended December 31, 2002 and 2001 was $14.9 million and $19.9 million, respectively. Prior to the adoption of SFAS 133 and for the year ended December 31, 2000, margin was $21.1 million.

Financial Contracts

In September 2001, the Company entered into several forward starting interest rate swaps with a total notional amount of $200.0 million in anticipation of VUHI's $250.0 million long-term debt issuance. Upon issuance of the debt in December 2001, the swaps were settled resulting in the Company receiving $0.9 million. The value received is being amortized from accumulated other comprehensive income to interest expense over the life of the debt.

In December 2000, the Company entered into an interest rate swap used to hedge interest rate risk associated with variable rate short-term notes payable totaling $150.0 million. The swap was entered into concurrently with the issuance of the floating rate notes on December 28, 2000 and swapped the debt's variable interest rate of three-month LIBOR plus 0.75% for a fixed rate of 6.64%. The swap expired on December 27, 2001, the date the debt agreement expired.

Prior to the adoption of SFAS 133, instruments hedging interest rate risk were accounted for upon settlement in interest expense. After adoption of SFAS 133, hedging instruments are carried at market value, and changes in market value are recorded in accumulated other comprehensive income, when effective, and are recorded to interest expense as settled.

As of December 31, 2002 and 2001, no interest rate swaps are outstanding. At December 31, 2002, approximately $0.8 million remains in accumulated other comprehensive income related to future interest payments. Of that amount, $0.1 million will be reclassified to earnings in 2003 and $0.1 million was reclassified to earnings during 2002.

Other Commodity-Related Operations

Other commodity contracts are generally settled by physical delivery or receipt and are within the normal operations of the Company. Contracts entered into that are probable of physical delivery or receipt receive accounting recognition upon settlement. Firm wholesale electric contracts are recorded in electric utility revenues. Certain contracts that purchase commodities for operational needs are recorded when settled in other operating expenses.

Impact of Adoption of SFAS 133

In June 1998, the FASB issued SFAS 133, which required that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its market value and that changes in the derivative's market value be recognized currently in earnings unless specific hedge or regulatory accounting criteria are met.

SFAS 133, as amended, required that as of the date of initial adoption, the difference between the market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivatives be reported in net income, other comprehensive income, or regulatory assets or liabilities, as appropriate. A change in earnings or other comprehensive income was reported as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes."

Resulting from the adoption of SFAS 133, certain non-firm wholesale power marketing contracts that are periodically settled net were required to be recorded at market value. Previously, the Company accounted for these contracts on settlement. The cumulative impact of the adoption of SFAS 133 resulting from marking these contracts to market on January 1, 2001 was an earnings gain of approximately $1.8 million ($1.1 million net of tax) recorded as a cumulative effect of accounting change. SFAS 133 did not impact other commodity contracts because they were normal purchases and sales specifically excluded from the provisions of SFAS 133 and did not impact the Company's cash flow hedges because they had no value on the date of adoption.

Fair Value of Other Financial Instruments

The carrying values and estimated fair values of the Company's other financial instruments follow:

	At December 31,			
	2002		2001	
In millions	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$ 911.9	$ 968.9	$ 918.4	$ 912.0
Short-term borrowings & notes payable	239.1	239.1	274.2	274.2
Short-term borrowings due to other Vectren companies	86.9	86.9	29.0	29.0

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's other financial instruments 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, its carrying amount approximates its fair value.

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 financial position or results of operations.

13. Additional Operational & Balance Sheet Information

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

	Year ended December 31,		
In millions	2002	2001	2000
AFUDC & capitalized interest	$ 5.3	$ 4.8	$ 5.0
Interest income	0.8	0.2	1.2
Other income	3.3	8.0	2.1
Other expense	(2.3)	(7.4)	(4.0)
Total other - net	$ 7.1	$ 5.6	$ 4.3

Other current assets in the Consolidated Balance Sheets consists of the following:

	At December 31,	
In millions	2002	2001
Prepaid gas delivery service	$ 70.3	$ 67.7
Prepaid taxes	4.8	8.7
Other prepayments & current assets	11.4	6.4
Total prepayments & other current assets	$ 86.5	$ 82.8

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

	At December 31,	
In millions	2002	2001
Accrued taxes	$ 27.3	$ 34.9
Refunds to customers & customer deposits	21.0	18.7
Accrued interest	13.4	12.9
Deferred income taxes	7.7	19.1
Accrued salaries & other	13.8	9.6
Total accrued liabilities	$ 83.2	$ 95.2

14. Segment Reporting

As discussed in Note 3, effective January 1, 2003, Vectren transferred certain information technology systems and related assets and buildings from other entities within its consolidated group to VUHI. These assets primarily support the operations of VUHI's subsidiaries. The operations of these assets comprise the Other Operations operating segment. The Company separates its operations into three operating segments: Gas Utility Services, Electric Utility Services, and Other Operations. The Company uses operating income as the measure of profitability for its segments.

Gas Utility Services provides natural gas distribution and transportation services in nearly two-thirds of Indiana and west central Ohio. Electric Utility Services provides electricity primarily to southwestern Indiana, and includes the Company's power generating and marketing operations. Other Operations provide information technology and other support services to those utility operations. Following is detailed information about the Company's operating segments.

	Year ended December 31,		
In millions	2002	2001	2000
Operating Revenues			
Gas Utility Services	$ 909.0	$ 1,019.6	$ 820.4
Electric Utility Services	608.1	381.2	334.4
Other Operations	22.3	29.1	33.5
Intersegment Eliminations	(22.0)	(28.9)	(33.2)
Total operating revenues	$1,517.4	$ 1,401.0	$ 1,155.1
Operating Income			
Gas Utility Services	$ 99.5	$ 44.9	$ 55.9
Electric Utility Services	100.1	77.6	74.0
Other Operations	8.1	8.9	6.2
Total operating income	$ 207.7	$ 131.4	$ 136.1
Depreciation & Amortization			
Gas Utility Services	$ 56.8	$ 58.5	$ 43.8
Electric Utility Services	40.0	38.7	38.6
Other Operations	13.9	20.7	22.2
Total depreciation & amortization	$ 110.7	$ 117.9	$ 104.6

	Year ended December 31,		
In millions	2002	2001	2000
Equity in Earnings of Unconsolidated Affiliates			
Gas Utility Services	$ 0.1	$ 0.7	$ -
Electric Utility Services	(1.9)	(1.2)	-
Total equity in earnings of unconsolidated affiliates	(1.8)	$ (0.5)	$ -
Capital Expenditures			
Gas Utility Services	$ 63.0	$ 77.8	$ 73.1
Electric Utility Services	88.8	69.8	37.6
Other Operations	65.5	55.2	8.0

Total capital expenditures	$ 217.3	$ 202.8	$ 118.7

	At December 31,	
In millions	2002	2001
Identifiable Assets		
Gas Utility Services	$1,555.1	$ 1,563.2
Electric Utility Services	860.9	807.6
Other Operations	165.6	120.0
Eliminations	(11.2)	(1.5)
Total identifiable assets	$2,570.4	$ 2,489.3

15. Special Charges for 2001 and 2000

Restructuring & Related Charges
As part of continued cost saving efforts, in June 2001, the Company's management and the board of directors approved a plan to restructure, primarily, its regulated operations. The restructuring plan included the elimination of certain administrative and supervisory positions in its utility operations and corporate office. Charges of $10.8 million were expensed in June 2001 as a direct result of the restructuring plan. Additional charges of $4.2 million were incurred during the remainder of 2001 primarily for consulting fees, employee relocation, and duplicate facilities costs. In total, the Company incurred restructuring charges of $15.0 million. These charges were comprised of $7.6 million for employee severance, related benefits and other employee related costs, $4.0 million for lease termination fees related to duplicate facilities and other facility costs, and $3.4 million for consulting and other fees.

The $7.6 million of severance and related costs includes $1.6 million of deferred compensation payable at various times through 2016 and $0.8 million of non-cash pension costs. The $4.0 million of lease termination fees includes $1.0 million of non-cash charges for impaired leasehold improvements. Restructuring expenses were incurred by the Company's operating segments as follows: $10.2 million by the Gas Utility Services segment and $4.8 million by the Electric Utility Services segment.

Employee severance and related costs are associated with approximately 100 employees. Employee separation benefits include severance, healthcare, and outplacement services. As of December 31, 2001, approximately 80 employees had exited the business. The restructuring program was completed during 2001, except for the departure of the remaining employees impacted by the restructuring which occurred during 2002 and the final settlement of the lease obligation which has yet to occur.

In June 2001, the Company established accruals totaling $8.2 million ($6.2 million for severance and $2.0 million for lease termination fees). Throughout 2001 additional expenses totaling $1.0 million for lease termination fees were incurred. Cash payments in 2001 totaled $4.9 million, all of which related to severance payments. As of December 31, 2001, the remaining accrual related to the restructuring was $4.3 million. Of that amount, $1.3 million remained accrued for severance, almost all of which relates to deferred compensation arrangements, and $3.0 million remained for lease termination fees. During 2002, the accrual for severance did not substantially change, and $1.0 million of lease costs were paid. At December 31, 2002, the remaining accrual was $3.6 million ($1.6 million for severance and $2.0 million for lease termination fees). The restructuring accrual is included in accrued liabilities.

Merger & Integration Costs

Merger and integration costs incurred for the years ended December 31, 2001 and 2000 were $2.8 million and $32.7 million, respectively. Merger and integration activities resulting from the 2000 merger were completed in 2001.

Since March 31, 2000, $35.5 million has been expensed associated with merger and integration activities. Accruals were established at March 31, 2000 totaling $19.3 million. Of this amount, $5.5 million related to employee and executive severance costs, $11.7 million related to transaction costs and regulatory filing fees incurred prior to the closing of the merger, and the remaining $2.1 million related to employee relocations that occurred prior to or coincident with the merger closing. The remaining $16.2 million was expensed through December 31, 2001 ($13.4 million in 2000 and $2.8 million in 2001) for accounting fees resulting from merger related filing requirements, consulting fees related to integration activities such as organization structure, employee travel between company locations as part of integration activities, internal labor of employees assigned to integration teams, investor relations communications activities, and certain benefit costs.

During the merger planning process, approximately 135 positions were identified for elimination. As of December 31, 2001, all such identified positions were vacated.

The integration activities experienced by the Company included such things as information system consolidation, process review and definition, organization design and consolidation, and knowledge sharing.

As a result of merger integration activities, management retired certain information systems in 2001. Accordingly, the useful lives of these assets were shortened in 2000 to reflect this decision. These information system assets are owned by a wholly owned subsidiary of Vectren, and the fees allocated by the subsidiary for the use of these systems by the Company's subsidiaries are reflected in other operating expenses. As a result of the shortened useful lives, additional fees were incurred by the Company, resulting in additional other operating expense of $9.6 million ($6.0 million after tax) for the year ended December 31, 2001 and $11.4 million ($7.1 million after tax) for the year ended December 31, 2000.

16. Impact of Recently Issued Accounting Guidance

EITF 02-03

In October 2002, the EITF reached a final consensus in EITF Issue 02-03 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) that gains and losses (realized and unrealized) on all derivative instruments within the scope of SFAS 133 should be shown net in the income statement, whether or not settled physically, if the derivative instruments are held for "trading purposes." The consensus rescinded EITF Issue 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10) as well as other decisions reached on energy trading contracts at the EITF's June 2002 meeting.

The Company's non-firm wholesale power marketing operations enter into contracts that are derivatives as defined by SFAS 133, but these operations do not meet the definition of energy trading activities based upon the provisions in EITF 98-10. Currently, the Company uses a gross presentation to report the results of these operations as described in Note 12. The Company has re-evaluated its portfolio of derivative contracts and has determined gross presentation remains appropriate.

SFAS 143

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. Any costs of removal recorded in accumulated depreciation pursuant to regulatory authority will require disclosure in future periods. The Company adopted this statement on January 1, 2003. The adoption was not material to the Company's results of operations or financial condition.

FASB Interpretation (FIN) 45

In November 2002, the FASB issued Interpretation 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 clarifies the requirements for a guarantor's accounting for and disclosure of certain guarantees issued and outstanding and that a guarantor is required to recognize, at the inception of a guarantee, a liability for the obligations it has undertaken. The objective of the initial measurement of that liability is the fair value of the guarantee at its inception. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. Although management is still evaluating the impact of FIN 45 on its financial position and results of operations, the adoption is not expected to have a material effect.

FIN 46

In January 2003, the FASB issued Interpretation 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 addresses consolidation by business enterprises of variable interest entities and significantly changes the consolidation requirements for those entities. FIN 46 is intended to achieve more consistent application of consolidation policies to variable interest entities and, thus improves comparability between enterprises engaged in similar activities when those activities are conducted through variable interest entities. FIN 46 applies to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. FIN 46 applies to the Company's third quarter for variable interest entities in which the Company holds a variable interest acquired before February 1, 2003. Although management is still evaluating the impact of FIN 46 on its financial position and results of operations, the adoption is not expected to have a material effect.

17. Subsidiary Guarantor and Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of VUHI's $325.0 million in short-term credit facilities and VUHI's $350.0 million unsecured senior notes. As a result of the asset transfer described in Note 3, VUHI has operations other than those of the subsidiary guarantors. Pursuant to Article 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors 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.

Consolidating Balance Sheet as of December 31, 2002:

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Assets				
Cash & cash equivalents	$ 10.2	$ 0.3	$ -	$ 10.5
Accounts receivable-less reserves	130.8	1.1	-	131.9
Receivables due from other Vectren companies	39.3	19.7	(2.7)	56.3
Accrued unbilled revenues	112.7	-	-	112.7
Inventories	56.0	-	-	56.0
Recoverable fuel & natural gas costs	22.1	-	-	22.1
Prepayments & other current assets	86.2	0.3	-	86.5
Total current assets	457.3	21.4	(2.7)	476.0
Utility Plant				
Original cost	3,037.2	-	-	3,037.2
Less: accumulated depreciation & amortization	1,389.0	-	-	1,389.0
Net utility plant	1,648.2	-	-	1,648.2
Investments in consolidated subsidiaries	-	802.4	(802.4)	-
Notes receivable from consolidated subsidiaries	8.5	493.9	(502.4)	-
Investments in unconsolidated affiliates	0.1	2.3	-	2.4
Other investments	13.1	8.8	-	21.9
Non-utility property-net	5.4	133.8	-	139.2
Goodwill-net	202.2	-	-	202.2
Regulatory assets	70.3	4.9	-	75.2
Other assets	4.9	0.4	-	5.3
TOTAL ASSETS	$2,410.0	$ 1,467.9	$(1,307.5)	$ 2,570.4
LIABILITIES & SHAREHOLDER'S EQUITY				
Current Liabilities				
Accounts payable	$ 71.3	$ 3.5	$ -	$ 74.8
Accounts payable to affiliated companies	85.2	0.4	-	85.6
Accounts payable due to other Vectren companies	61.3	11.2	(2.7)	69.8
Accrued liabilities	83.8	1.7	(2.3)	83.2
Short-term borrowings	-	239.1	-	239.1
Short-term borrowings due from other Vectren companies	147.6	95.4	(156.1)	86.9
Current maturities of long-term debt	39.8	-	-	39.8
Long-term debt subject to tender	26.6	-	-	26.6
Total current liabilities	515.6	351.3	(161.1)	705.8
Long-Term Debt				
Long-term debt-net of current maturities & debt subject to tender	492.8	348.4	-	841.2
Long-term debt due to VUHI	344.0	-	(344.0)	-
Total long-term debt-net	836.8	348.4	(344.0)	841.2
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	174.6	(2.3)	-	172.3

Deferred credits & other liabilities	80.3	1.9	-	82.2
Total deferred credits & other liabilities	254.9	(0.4)	-	254.5
Cumulative, Redeemable Preferred Stock of a Subsidiary	0.3	-	-	0.3
Common Shareholder's Equity				
Common stock (no par value)	461.3	385.7	(461.3)	385.7
Retained earnings	341.1	382.4	(341.1)	382.4
Accumulated other comprehensive income	-	0.5	-	0.5
Total common shareholder's equity	802.4	768.6	(802.4)	768.6
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$2,410.0	$ 1,467.9	$(1,307.5)	$ 2,570.4

Consolidating Balance Sheet as of December 31, 2001:

ASSETS	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
Current Assets				
Cash & cash equivalents	$ 7.0	$ (1.8)	$ -	$ 5.2
Accounts receivable-less reserves	123.0	0.1	-	123.1
Receivables due from other Vectren companies	56.0	31.8	(1.5)	86.3
Accrued unbilled revenues	77.1	-	-	77.1
Inventories	54.8	-	-	54.8
Recoverable fuel & natural gas costs	70.2	-	-	70.2
Prepayments & other current assets	84.8	(2.0)	-	82.8
Total current assets	472.9	28.1	(1.5)	499.5
Utility Plant				
Original cost	2,906.1	-	-	2,906.1
Less: accumulated depreciation & amortization	1,308.2	-	-	1,308.2
Net utility plant	1,597.9	-	-	1,597.9
Investments in consolidated subsidiaries	-	754.4	(754.4)	-
Notes receivable from consolidated subsidiaries	-	544.3	(544.3)	-
Investments in unconsolidated affiliates	0.2	3.3	-	3.5
Other investments	11.2	8.8	-	20.0
Non-utility property-net	6.3	78.7	-	85.0
Goodwill-net	201.5	-	-	201.5
Regulatory assets	62.6	5.2	-	67.8
Other assets	13.9	0.2	-	14.1

TOTAL ASSETS	$2,366.5	$1,423.0	$(1,300.2)	$2,489.3
LIABILITIES & SHAREHOLDER'S EQUITY				
Current Liabilities				
Accounts payable	$ 76.3	$ 3.1	$ -	$ 79.4
Accounts payable to affiliated companies	37.4	-	-	37.4
Accounts payable due to other Vectren companies	29.1	24.0	(1.5)	51.6
Accrued liabilities	93.3	4.8	(2.9)	95.2
Short-term borrowings	0.9	273.3	-	274.2
Short-term borrowings due from other Vectren companies	234.5	29.0	(234.5)	29.0
Current maturities of long-term debt	1.3	-	-	1.3
Long-term debt subject to tender	11.5	-	-	11.5
Total current liabilities	484.3	334.2	(238.9)	579.6
Long-Term Debt				
Long-term debt-net of current maturities & debt subject to tender	552.7	348.2	-	900.9
Long-term debt due to VUHI	306.9	-	(306.9)	-
Total long-term debt-net	859.6	348.2	(306.9)	900.9
Deferred Income Taxes & Other Liabilities				
Deferred income taxes	176.0	0.5	-	176.5
Deferred credits & other liabilities	91.7	1.2	-	92.9
Total deferred credits & other liabilities	267.7	1.7	-	269.4
Cumulative, Redeemable Preferred Stock of a Subsidiary	0.5	-	-	0.5
Common Shareholder's Equity				
Common stock (no par value)	436.3	385.7	(436.3)	385.7
Retained earnings	320.5	355.0	(320.5)	355.0
Accumulated other comprehensive income	(2.4)	(1.8)	2.4	(1.8)
Total common shareholder's equity	754.4	738.9	(754.4)	738.9
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$2,366.5	$1,423.0	$(1,300.2)	$ 2,489.3

Consolidating Statement of Income for the year ended December 31, 2002:

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 909.0	$ -	$ -	$ 909.0
Electric utility	608.1	-	-	608.1

Other	-	22.3	(22.0)	0.3
Total operating revenues	1,517.1	22.3	(22.0)	1,517.4
OPERATING EXPENSES				
Cost of gas sold	571.8	-	-	571.8
Fuel for electric generation	81.6	-	-	81.6
Purchased electric energy	296.3	-	-	296.3
Other operating	220.2	0.4	(22.0)	198.6
Depreciation & amortization	96.8	13.9	-	110.7
Taxes other than income taxes	50.8	(0.1)	-	50.7
Total operating expenses	1,317.5	14.2	(22.0)	1,309.7
OPERATING INCOME	199.6	8.1	-	207.7
OTHER INCOME (EXPENSE) - NET				
Equity in earnings of consolidated companies	-	95.3	(95.3)	-
Equity in losses of unconsolidated affiliates	-	(1.8)	-	(1.8)
Other - net	5.0	27.6	(25.5)	7.1
Total other income (expense) - net	5.0	121.1	(120.8)	5.3
Interest expense	63.6	31.0	(25.5)	69.1
INCOME BEFORE INCOME TAXES	141.0	98.2	(95.3)	143.9
Income taxes	45.7	1.1	-	46.8
NET INCOME	$ 95.3	$ 97.1	$(95.3)	$ 97.1

Consolidating Statement of Income for the year ended December 31, 2001:

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidate
OPERATING REVENUES				
Gas utility	$1,019.6	$ -	$ -	$ 1,019.6
Electric utility	381.2	-	-	381.2
Other	-	29.1	(28.9)	0.2
Total operating revenues	1,400.8	29.1	(28.9)	1,401.0
OPERATING EXPENSES				
Cost of gas sold	708.9	-	-	708.9
Fuel for electric generation	74.4	-	-	74.4
Purchased electric energy	86.9	-	-	86.9
Other operating	241.9	(0.9)	(28.9)	212.1
Merger & integration costs	2.8	-	-	2.8
Restructuring costs	15.0	-	-	15.0
Depreciation & amortization	97.2	20.7	-	117.9

Taxes other than income taxes	51.2	0.4	-	51.6
Total operating expenses	1,278.3	20.2	(28.9)	1,269.6
OPERATING INCOME	122.5	8.9	-	131.4
OTHER INCOME (EXPENSE) - NET				
Equity in earnings of consolidated companies	-	40.1	(40.1)	-
Equity in losses of unconsolidated affiliates	-	(0.5)	-	(0.5
Other - net	4.9	23.0	(22.3)	5.6
Total other income (expense) - net	4.9	62.6	(62.4)	5.1
Interest expense	67.5	25.5	(22.3)	70.7
INCOME BEFORE INCOME TAXES	59.9	46.0	(40.1)	65.8
Income taxes	19.0	2.3	-	21.3
Preferred dividend requirements of subsidiary	1.9	-	(1.1)	0.8
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	39.0	43.7	(39.0)	43.7
Cumulative effect of change in accounting principle - net of tax	1.1	-	-	1.1
NET INCOME	$ 40.1	$ 43.7	$ (39.0)	$ 44.8

Consolidating Statement of Income for the year ended December 31, 2000:

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 820.4	$ -	$ -	$ 820.4
Electric utility	334.4	-	-	334.4
Other	-	33.5	(33.2)	0.3
Total operating revenues	1,154.8	33.5	(33.2)	1,155.1
OPERATING EXPENSES				
Cost of gas sold	552.5	-	-	552.5
Fuel for electric generation	75.7	-	-	75.7
Purchased electric energy	36.4	-	-	36.4
Other operating	209.0	4.8	(33.2)	180.6
Merger & integration costs	32.7	-	-	32.7
Restructuring costs	-	-	-	-
Depreciation & amortization	82.4	22.2	-	104.6
Taxes other than income taxes	36.2	0.3	-	36.5
Total operating expenses	1,024.9	27.3	(33.2)	1,019.0
OPERATING INCOME	129.9	6.2	-	136.1
OTHER INCOME (EXPENSE) - NET				
Equity in earnings of consolidated companies	-	52.5	(52.5)	-

Equity in losses of unconsolidated affiliates	-	-	-	-
Other - net	3.8	4.6	(4.1)	4.3
Total other income (expense) - net	3.8	57.1	(56.6)	4.3
Interest expense	45.2	5.3	(4.1)	46.4
INCOME BEFORE INCOME TAXES	88.5	58.0	(52.5)	94.0
Income taxes	35.0	2.1	-	37.1
Preferred dividend requirements of subsidiary	1.0	-	-	1.0
NET INCOME	$ 52.5	$ 55.9	$ (52.5)	$ 55.9

Consolidating Statement of Cash Flows for the year ended December 31, 2002:

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	$ 269.4	$ 8.2	$ -	$ 277.6
CASH FLOWS REQUIRED FOR FINANCING ACTIVITIES				
Proceeds from:				
Capital contribution	25.0	-	(25.0)	-
Long-term debt	37.1	-	(37.1)	-
Requirements for:				
Retirement of long-term debt, including premiums paid	(6.5)	-	-	(6.5)
Dividends on common stock	(74.7)	(69.7)	74.7	(69.7)
Redemption of preferred stock of subsidiary	(0.2)	-	-	(0.2)
Net change in short-term borrowings, including to other Vectren companies	(88.4)	32.2	79.0	22.8
Net cash flows required for financing activities	(107.7)	(37.5)	91.6	(53.6)
CASH FLOW FROM (REQUIRED FOR) INVESTING ACTIVITIES				
Proceeds from consolidated subsidiary distributions				
Consolidated subsidiary distributions	-	74.7	(74.7)	-
Other investing activities	1.5	8.9	-	10.4
Requirements for:				
Capital expenditures, excluding AFUDC-equity	(147.6)	(69.7)	-	(217.3)
Consolidated subsidiary investments	-	(25.0)	25.0	-
Other investing activities	(3.9)	(7.9)	-	(11.8)
Net change in notes receivable to other Vectren companies	(8.5)	50.4	(41.9)	-

Net cash flows from (required for) investing activities	(158.5)	31.4	(91.6)	(218.7)
Net increase in cash & cash equivalents	3.2	2.1	-	5.3
Cash & cash equivalents at beginning of period	7.0	(1.8)	-	5.3
Cash & cash equivalents at end of period	$ 10.2	$ 0.3	$ -	$ 10.6

Consolidating Statement of Cash Flows for the year ended December 31, 2001:

	Subsidiary Guarantors	Parent Company	Eliminations	Consolid
NET CASH FLOWS FROM OPERATING ACTIVITIES	$ 141.0	$ 44.3	$ -	$ 185
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Capital contribution	214.7	164.4	(214.7)	164
Long-term debt	307.0	344.0	(307.0)	344
Requirements for:				
Retirement of long-term debt, including premiums paid	(7.3)	-	-	(7
Retirement of short-term notes payable	-	(150.0)	-	(150
Dividends on common stock	(62.5)	(91.6)	62.5	(91
Redemption of preferred stock of subsidiary	(17.7)	-	-	(17
Dividends on preferred stock of subsidiary	(0.8)	-	-	(0
Net change in short-term borrowings, including to other Vectren companies	(414.3)	(30.9)	238.1	(207
Net cash flows from financing activities	19.1	235.9	(221.1)	33
CASH FLOWS REQUIRED FOR INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	-	62.5	(62.5)	
Other investing activities	1.5	-	-	1
Requirements for:				
Capital expenditures, excluding AFUDC-equity	(154.4)	(48.4)	-	(202
Acquisition of the Ohio operations	(2.2)	-	-	(2
Consolidated subsidiary investments	-	(214.7)	214.7	
Other investing activities	-	(11.8)	-	(11
Net change in notes receivable to other Vectren companies	-	(68.9)	68.9	
Net cash flows required for investing activities	(155.1)	(281.3)	221.1	(215
Net increase (decrease) in cash & cash equivalents	5.0	(1.1)	-	3
Cash & cash equivalents at beginning of period	2.0	(0.7)	-	1
Cash & cash equivalents at end of period	$ 7.0	$ (1.8)	$ -	$ 5

Consolidating Statement of Cash Flows for the year ended December 31, 2000:

	Subsidiary Guarantors	Parent Company	Eliminations	Consol
NET CASH FLOWS FROM OPERATING ACTIVITIES	$ 23.2	$ 11.9	$ -	$
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Short-term notes payable	-	150.0	-	
Long-term debt	67.9	-	-	
Other proceeds	1.6	-	-	
Requirements for:				
Retirement of long-term debt, including premiums paid	(0.7)	-	-	
Dividends on common stock	(55.0)	(60.6)	55.0	
Redemption of preferred stock of subsidiary	(2.0)	-	-	
Dividends on preferred stock of subsidiary	(1.0)	-	-	
Net change in short-term borrowings, including to other Vectren companies	547.4	333.2	(475.4)	
Net cash flows from financing activities	558.2	422.6	(420.4)	
CASH FLOWS (REQUIRED FOR) INVESTING ACTIVITIES				
Proceeds from consolidated subsidiary distributions	-	55.0	(55.0)	
Requirements for:				
Capital expenditures, excluding AFUDC-equity	(103.9)	(14.8)	-	(
Acquisition of the Ohio operations	(469.2)	-	-	(
Other investing activities	(7.1)	-	-	
Net change in notes receivable to other Vectren companies	-	(475.4)	475.4	
Net cash flows (required for) investing activities	(580.2)	(435.2)	420.4	(
Net increase (decrease) in cash & cash equivalents	1.2	(0.7)	-	
Cash & cash equivalents at beginning of period	0.8	-	-	
Cash & cash equivalents at end of period	$ 2.0	$ (0.7)	$ -	$

18. Quarterly Financial Data (Unaudited)

As more fully described in Note 3, the Company has restated the results for the year ended December 31, 2001, including each quarter, as well as the first three quarters of 2002 to appropriately account for certain errors and a transfer of assets between entities under common control. Provided below is a comparison of restated summarized quarterly financial data to summarized quarterly financial data previously reported. Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company's utility operations.

Summarized quarterly financial data for 2002 follows:

In millions	Q1		Q2 (5)		Q3		Q4
2002 Operating data	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported
Operating revenues	$ 483.9	$485.0	$ 298.7	$299.1	$ 278.1	$278.1	$ 455.2
Operating income (6)	78.6	80.8	21.1	26.0	29.9	30.3	70.6
Net income	40.6	42.0	9.1	8.7	8.9	9.0	37.4

Summarized quarterly financial data for 2001 follows:

In millions	Q1 (1)		Q2 (2)		Q3		Q4
2001 Operating Data (3)	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported
Operating revenues	$ 611.9	$614.8	$ 249.6	$248.5	$ 200.3	$196.7	$ 348.6
Operating income (loss) (6)	70.2	77.2	(3.8)	(1.5)	14.6	15.5	54.4
Income (loss) before extraordinary loss & cumulative effect of change in accounting principle	31.8	36.5	(12.9)	(11.9)	(0.5)	(0.2)	28.4
Net income (loss)	35.7	37.6	(12.9)	(11.9)	(0.5)	(0.2)	28.4

1. Q1 of 2001 includes charges for cumulative effect of changes in accounting principle as described in Note 12.
2. Q2 of 2001 includes restructuring charges as described in Note 15.
3. 2001 includes merger and integration charges as described in Note 15.
4. The benefit clearing adjustment and primarily all of the inventory adjustment discussed in Note 3 were recorded in Q4 of 2001.
5. In Q2 of 2002, the Company recorded $3.2 million of after tax carrying costs for DSM programs pursuant to existing IURC orders. Management determined that the accrual of such carrying costs was more appropriate in periods prior to 2000 when DSM program expenditures were made. Therefore, such carrying costs originally reflected in Q2 of 2002 were reversed and reflected in common shareholder's equity as of January 1, 2000.
6. Operating income (loss) in the "As Reported" columns has been adjusted to reflect the reclassification of income taxes which prior to Q4 of 2002 was included as a component of operating income, consistent with traditional

regulated entity income statement presentation. The income statement presentation was changed to the commercial and industrial presentation described in Article 5 of Regulation S-X.

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

Disclosure with respect to this Item, has been previously provided on Form 8-K originally filed with the SEC on March 26, 2002, as amended on Form 8-K/A filed with the SEC on May 20, 2002.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Certain information required to be shown for Item 10, Directors and Executive Officers of the Registrant, is incorporated by reference, with the exception of the Compensation Committee Report and Performance Graph, from the Proxy Statement of the registrant's parent company, Vectren Corporation. That report was prepared and filed electronically with the Securities and Exchange Commission on March 27, 2003, and is attached to this filing as Exhibit 99.1.

Directors

Niel C. Ellerbrook, age 54, has been a director of Indiana Energy or the Company since 1991. Mr. Ellerbrook is Chairman of the Board and Chief Executive Officer of the Company, having served in that capacity since March 2000. Mr. Ellerbrook served as President and Chief Executive Officer of Indiana Energy from June 1999 to March 2000. Mr. Ellerbrook served as President and Chief Operating Officer of Indiana Energy from October 1997 to March 2000. From January through October 1997, Mr. Ellerbrook served as Executive Vice President, Treasurer, and Chief Financial Officer of Indiana Energy; and from 1986 to January 1997 as Vice President, Treasurer, and Chief Financial Officer of Indiana Energy. Mr. Ellerbrook is a director of Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., and Southern Indiana Gas and Electric Co. He is also a director of Old National Bancorp and Deaconess Hospital of Evansville, Indiana.

Andrew E. Goebel, age 55, has been a director of SIGCORP or the Company since 1997. Mr. Goebel is President and Chief Operating Officer of the Company, having served in that capacity since March 2000. Mr. Goebel was President and Chief Operating Officer of SIGCORP from April 1999 to March 2000. From September 1997 through April 1999, Mr. Goebel served as Executive Vice President of SIGCORP; and from 1996 to September 1997, he served as Secretary and Treasurer of SIGCORP. Mr. Goebel is a director of Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., and Southern Indiana Gas and Electric Co. Mr. Goebel is also a director of Old National Bancorp and Old National Bank. Mr. Goebel is retiring from the Company effective April 30, 2003.

Jerome A. Benkert, Jr., age 44, has served as Executive Vice President and Chief Financial Officer of the Company since March 2000 and as Treasurer of the Company since October 2001 to April 2002. He was Executive Vice President and Chief Operating Officer of Indiana Energy's administrative services company from October 1997 to March 2000. Mr. Benkert has served as Controller and Vice President of Indiana Gas. Mr. Benkert is a director of Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Co., and Fifth Third Bank, Indiana.

Ronald E. Christian, age 44, has served as Senior Vice President and Secretary of the Company since March 2000. Mr. Christian served as Vice President and General Counsel of Indiana Energy from July 1999 to March 2000. From June 1998 to July 1999, Mr. Christian was the Vice President, General Counsel and Secretary of Michigan Consolidated Gas Company in Detroit, Michigan. He served as the General Counsel and Secretary of Indiana Energy, Indiana Gas and Indiana Energy Investments, Inc. from 1993 to June 1998. Mr. Christian is a director of Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., and Southern Indiana Gas and Electric Co.

William S. Doty, age 52, has served as a director since June 2001. Mr. Doty has also served as Senior Vice President-Energy Delivery of the Company since April 2001. Mr. Doty served as Senior Vice President of Customer Relationship Management from January 2001 to April 2001. From January 1999 to January 2001, Mr. Doty was Vice President of Energy Delivery for Southern Indiana Gas and Electric Company and previous to January 1999, he was Director of Gas Operations. Mr. Doty is a director of Southern Indiana Gas and Electric Company.

Other Executive Officer

Richard G. Lynch, age 51, has served as Senior Vice President-Human Resources and Administration of the Company since March 2000. Mr. Lynch was Vice President of Human Resources for SIGCORP from March 1999 to March 2000. Prior to joining the Company, Mr. Lynch was the Director of Human Resources for the Mead Johnson Division of Bristol Myers-Squibb in Evansville, Indiana.

ITEM 11. EXECUTIVE COMPENSATION

Certain information required to be shown for Item 11, Executive Compensation, is incorporated by reference, with the exception of the Compensation Committee Report and Performance Graph, from the Proxy Statement of the registrant's parent company, Vectren Corporation. That report was prepared and filed electronically with the Securities and Exchange Commission on March 27, 2003, and is attached to this filing as Exhibit 99.1.

The compensation of Niel C. Ellerbrook, Andrew E. Goebel, Jerome A Benkert, Jr., and Ronald E. Christian is included in Exhibit 99.1 attached to this filing. In addition to these named executive officers, the compensation of William S. Doty is presented below. The compensation presented below and the compensation included in Exhibit 99.1 represents each executive's Vectren-wide compensation, not just the portion allocated to VUHI. The tables include a Summary Compensation Table (Table I), a Summary of Option Grants in Last Fiscal year (Table II), a table showing Aggregate Option Exercises in Last Fiscal Year and Fiscal Year End Option Values (Table III) and a table showing the Long-Term Incentive Plan Awards in Last Fiscal Year (Table IV).

TABLE I
SUMMARY COMPENSATION TABLE

(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)
		Annual Compensation			Long-term Compensation Payouts		
Name and Principal Position at VUHI	Year	Salary ($)	Bonus ($) (1)	Other Compen-sation ($) (2)	Options (# shares) (3)	LTIP Payouts ($) (4)	Other Compen-sation ($) (5)
William S. Doty	2002	189,654	61,737	5,931	15,000	-	10,739
Senior Vice President -	2001	174,608	10,500	5,709	22,000	-	12,836
Energy Delivery	2000	141,464	96,125	1,413	-	-	18,079

Earnings are shown on a calendar year basis.

(1) The amounts shown in this column for 2002 and 2001 are exclusively payments under the Company's At-Risk Compensation Plan, which is discussed above in Part B, relating to "Annual Incentive Compensation," and Part B of the Compensation and Benefits Committee Report in Exhibit 99.1.

The amounts shown in this column for 2000 include payments under the Company's Executive Annual Incentive Plan and the SIGCORP Corporate Performance Plan. Payments in 2000 attributable to the Company's Executive Annual Incentive Plan for the performance period of April 1 to December 1, 2000 (Mr. Doty, $64,000). Also, at the close of the merger of Indiana Energy and SIGCORP into the Company on March 31, 2000, the existing annual incentive programs of the two companies were terminated and a "stub year" payout was made based on the portion of the performance cycle that had passed. For the SIGCORP Performance Plan, a prorated payout for three months, January 1, 2000 to March 31, 2000 was made. For Mr. Doty, this stub year bonus was $6,250. Also included in 2000 for Mr. Doty, ($25,875) is the payment attributable to SIGCORP's performance for the period January 1 to December 31, 1999.

(2) The amounts shown in this column are dividends paid on restricted shares issued under the Vectren Corporation Executive Restricted Stock Plan (formerly the Indiana Energy Executive Restricted Stock Plan), which was adopted by the Company on March 31, 2000. No restricted shares were issued to executives in 2001 and 2002. Mr. Doty did not participate in the Stock Plan prior to March 31, 2000.

(3) The options shown were issued under the Company's At-Risk Compensation Plan. For further information, see the discussion in Part B relating to "Long-term Incentive Compensation," and Part C of the Compensation and Benefits Committee Report in Exhibit 99.1.

(4) The amounts shown in this column represent the value of shares issued under the Vectren Corporation Restricted Stock Plan and for which restrictions were lifted in each year. At the time of the merger, Indiana Energy executives had restricted stock performance grants relating to open performance measurement periods. (Under normal circumstances, at the close of each performance cycle, Indiana Energy's Total Shareholder Return would have been compared to a peer group and the number of restricted shares granted would have been adjusted in accordance with the plan.) The Board concluded that it would be difficult, if not inappropriate, to use Vectren's performance to make adjustments to the prior grants. Based upon the frequency of past performance grants, the Board awarded 75 percent of the present value of the potential performance grants. Mr. Doty did not participate in the plan prior to March 31, 2000.

(5) The amount shown in this column represents several compensation elements.

For Mr. Doty, this column also contains income related to reimbursement for taxable expenses (2002 -- $5,239; 2001 -- $5,680; 2000 -- $2,520), imputed earnings from automobile usage (Mr. Doty: 2000 -- $1,167), Company contributions to the retirement savings plan (2002 -- $5,500; 2001 -- $5,100; 2000 -- $5,100), and deferred compensation contributions to restore contributions to the company Retirement Savings Plan (2001 -- $2,056; 2000 -- $900). At the close of the merger, officers coming from SIGCORP were no longer furnished with company automobiles (Indiana Energy executives were not furnished with company automobiles). As a result of the termination of this perquisite, Mr. Doty was given a one-time automobile buyout of $8,392, paid in 2000.

TABLE II
OPTION GRANTS IN LAST FISCAL YEAR

Name	Number of Shares Underlying Options/ SARs Granted	% of Total Options Granted to Employees in Fiscal Year	Exercise or Base Price (Per Share) ($)	Expiration Date	Grant Date Present Value
	(#) (1)				($)
W.S. Doty	15,000/0	3.29%	23.19	1/1/2013	$70,088

(1) On December 11, 2002, a total of 384,500 options were awarded effective as of January 1, 2003 to all plan participants under the Vectren Corporation At-Risk Compensation Plan. Stock options are exercisable upon vesting in whole or in part and expire ten years from the date of grant. This grant has a vesting schedule pursuant to which 34 percent vests at the end of the first year, and 33 percent vests at the end of the second and third years.

(2) The assumptions used for the Model are as follows: Volatility -- 23.69 percent based on monthly stock prices for the period of January 1, 2000 to December 31, 2002; Risk-free rate of return -- 4.54 percent; Dividend Yield -- 4.78 percent over the period of January 1, 2000 to December 31, 2002; and, a ten-year exercise term. A discount rate of .9412 was applied to reflect a 3-year graduated vesting schedule. (Per a binomial model as certified by an independent consultant retained by the Compensation and Benefits committee.)

TABLE III
AGGREGATED OPTION EXERCISES IN LAST FISCAL YEAR
AND FISCAL YEAR-END OPTION VALUES
FROM 1/1/2001 TO 12/31/2001

Name	Shares Acquired On Exercise(#)	Underlying Unexercised Value Realized ($)	Number of Securities Underlying Unexercised Options at Year-End (#) (1)		Value of Unexercise In-the-Money Options as of 12/31/01	
			Exercisable	Unexercisable	Exercisable	Unexerc
W.S. Doty	1,631	14,033	30,657	28,200	99,965	6,0

(1) Includes grants authorized by the Compensation and Benefits Committee on December 11, 2002 to be effective as of January 1, 2003.

TABLE IV

LONG-TERM INCENTIVE PLAN AWARDS IN LAST FISCAL YEAR

			Estimated Future Payouts Under Non-Stock Price-Based Plans		
(a)	(b)	(c)	(d)	(e)	(f)
	Number of Shares; Units or Other Rights (1)	Performance or Other Periods Until Maturation or Payout (2)	Threshold Number of Shares (3)	Target Number of Shares (4)	Maximum Number of Shares (5)
W.S. Doty	4,000	0	1,500	4,000	8,000

(1) This column reflects restricted stock grants awarded under the Vectren Corporation At-Risk Compensation Plan by the Compensation and Benefits Committee on December 11, 2002, to be effective January 1, 2003. The manner for determining the awards, and other terms and conditions of the At-Risk Plan, are discussed in the Compensation and Benefits Committee Report relating to "Long-Term Incentive Compensation." The market value of the shares on the date of grant is determined by the market price on the date of grant or, if no trading occurs on that date, the market price on the next trading day on which shares are traded. Dividends are paid directly to the holders of the stock.

(2) As discussed in the Compensation and Benefits Committee Report relating to "Long-Term Incentive Compensation" in Exhibit 99.1, for the grant authorized on December 11, 2002 and granted on January 1, 2003, the measurement period commenced on January 1, 2003 and will conclude on December 31, 2005.

(3) The ultimate amount of the grant will be determined by the Company's performance relative to its peer group. Performance at the 25th percentile will result in a threshold payment equal to 0.375 of the initial grant which is shown in column (b), and in column (e). Performance versus the peer group which is below the 25th percentile will result in a complete forfeiture.

(4) The total number of shares in column (b), and also set forth in column (e), are subject to forfeiture as discussed in footnote (3). If the Company's performance compared to the peer group during the measurement period places it above 25% and below 90%, linear interpolation will be employed to perform the award calculation. At target, the payment will be equal to the initial grant which is shown in column (b).

(5) Under the At-Risk Plan, if the Company's performance compared to the peer group during the measuring period places it in the 90th percentile, an additional performance grant equal to the original grant will be made. In that event, the shares shown in column (e) will be doubled.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Security ownership of certain beneficial owners

As of December 31, 2002, the following stockholder was known to the management to be the beneficial owner of more than five percent of the outstanding shares of any class of voting securities as set forth below.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common	Vectren Corporation 20 N.W. Fourth Street Evansville, IN 47708	10 Shares Registered Owner	100 percent

Security ownership of management

The following table sets forth the beneficial ownership, as of December 31, 2002, of Vectren common stock, by each director and named executive officer in Item 11 Executive Compensation. Also shown is the total ownership for such persons as a group. Except as otherwise indicated, each individual has sole voting and investment power with respect to the shares listed below.

Name of Beneficial Owner	Shares Owned Beneficially (1)	
Niel C. Ellerbrook	210,837	(2) (3) (6) (8)
Andrew E. Goebel	187,976	(2) (3) (4) (5)
Jerome A. Benkert, Jr.	49,253	(2) (4) (5)
Ronald E. Christian	48,253	(2) (4) (5)
William S. Doty	43,047	(2) (4) (5)

All Directors and Named Executive Officers as a Group (5 Persons): 539,366 (1)

(1) No director, executive officer, or directors and executive officers as a group owned beneficially as of December 31, 2002, more than 1 percent of common stock of Vectren.

(2) This amount does not include derivative securities held under the Company's Non-Qualified Deferred Compensation Plan. These derivative securities are in the form of phantom stock units which are valued as if they were Company Common Stock. The amounts shown for the following individuals include the following amounts of phantom units:

Name of Individuals or Identity of Group	Phantom Stock Units
Niel C. Ellerbrook	53,837
Andrew E. Goebel	2,654
Jerome A. Benkert, Jr.	16,436
Ronald E. Christian	27,511
William S. Doty	677
All Directors and Executive Officers as a Group (6 Persons)	101,115

(3) Includes shares held by spouse or jointly with spouse.

(4) Includes shares granted to executives under the Company's Executive Restricted Stock Plan and restricted stock award granted to certain executives on January 1, 2003 under the Company's At-Risk Compensation Plan. These shares are subject to certain transferability restrictions and forfeiture provisions.

(5) Includes shares which the named individual has the right to acquire as of March 3, 2003, or within sixty (60) days thereafter, under the Vectren

Corporation Stock Option Plan.

Equity Compensation Plan Information

VUHI does not have equity compensation plans separate from Vectren. The information with respect to common shares issuable under Vectren equity compensation plans as of December 31, 2002 is included below.

	(a)	(b)	(c)
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)
Equity compensation plans approved by security holders (1)	1,733,762 (2)	$ 21.86	2,909,316 (3)
Equity compensation plans not approved by security holders	0	0	0
Total	1,733,762	$ 21.86	2,909,316

(1) Includes the following Vectren Corporation Plans: Vectren Corporation At-Risk Compensation Plan, 1994 SIGCORP Stock Option Plan, Vectren Corporation Executive Restricted Stock Plan, and Vectren Corporation Directors Restricted Stock Plan.
(2) Includes a stock option grant approved by the Board of Directors' Compensation Committee on December 11, 2002, effective January 1, 2003.
(3) Includes shares available for issuance under the Vectren Corporation At-Risk Compensation Plan (2,678,027), of which up to 800,000 shares may be issued in restricted stock, Vectren Corporation Executive Restricted Stock Plan (186,098), and Vectren Corporation Directors Restricted Stock Plan (45,191).

The SIGCORP stock option plan was approved by SIGCORP common shareholders prior to the merger forming Vectren, and both the directors and executive restricted stock plans were approved by Indiana Energy common shareholders prior to the merger forming Vectren. The At-Risk Compensation plan was approved by Vectren Corporation common shareholders after the merger forming Vectren.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Transactions with Vectren and Vectren Affiliates

Refer to Notes 4 and 5 to the Company's financial statements included in Item 8 Financial Statements and Supplementary Data for transactions with other Vectren companies and Vectren affiliates.

Transactions with Directors and Officers

Andrew E. Goebel is a director and President of the Company and a director and President and Chief Operating Officer of Vectren. During 2002 and 2001, Hasgoe Cleaning Systems, a cleaning company owned by Mr. Goebel's brother's family, performed certain cleaning services for the Company and is expected to perform such services in 2003. During 2002, the cost of such services was $221,745, which the Company believes to be a fair and reasonable price for the services rendered.

PART IV

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Within 90 days prior to the filing of the report, the Company carried out an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective in bringing to their attention on a timely basis material information relating to the Company required to be disclosed by the Company in its filings under the Securities Exchange Act of 1934 (Exchange Act).

Disclosure controls and procedures, as defined by the Exchange Act in Rules 13a-14(c) and 15d-14(c), are controls and other procedures of the Company that are designed to ensure that information required to be disclosed by the Company in the reports filed or submitted by it under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms. "Disclosure controls and procedures" include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in its Exchange Act reports is accumulated and communicated to the Company's management, including its principal executive and financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control

Since the evaluation of disclosure controls and procedures, there have been no significant changes to the Company's internal controls and procedures or significant changes in other factors that could significantly affect the Company's internal controls and procedures. However, in Note 3 to the consolidated financial statements (included in Item 8) which discusses the restatement of 2001 and 2000 previously reported information, the Company identified certain errors, the net effect of which, related primarily to gas inventory accounting and the proper clearing of employee benefit related costs routinely accumulated on the balance sheet. These errors resulted primarily from insufficient account reconciliation procedures. The Company has taken steps to improve these internal controls.

Internal control, as defined in American Institute of Certified Public Accountants Codification of Statements on Auditing Standards (AU ss.319), is a process, effected by an entity's board of directors, management, and other personnel, designed to provide reasonable assurance regarding the achievement of objectives in the following categories: (a) reliability of financial reporting, (b) effectiveness and efficiency of operations and (c) compliance with applicable laws and regulations.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

List Of Documents Filed As Part Of This Report

Consolidated Financial Statements

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

Supplemental Schedules

For the years ended December 31, 2002, 2001, and 2000, the Company's Schedule II -- Valuation and Qualifying Accounts Consolidated Financial Statement Schedules is presented on page 83. The report of Deloitte & Touche LLP on the schedule may be found in Item 8.

All other schedules are omitted as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or related notes in Item 8.

List of Exhibits

The Company has incorporated by reference herein certain exhibits as specified below pursuant to Rule 12b-32 under the Exchange Act.

Exhibits for the Company are listed in the Index to Exhibits beginning on page 85.
Exhibits for the Company attached to this filing filed electronically with the SEC are listed on page 90.

Reports On Form 8-K During The Last Calendar Quarter

On October 25, 2002 Vectren Utility Holdings, Inc. filed a Current Report on Form 8-K with respect to the release of financial information to the investment community regarding Vectren Corporation's results of operations, financial position and cash flows for the three, nine, and twelve month periods ended September 30, 2002. The financial information was released to the public through this filing.

Item 5. Other Events
Item 7. Exhibits
99.1 - Press Release - Third Quarter 2002 Vectren Corporation Earnings
99.2 - Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

On November 27, 2002, Vectren Utility Holdings, Inc. filed a Current Report on Form 8-K with respect to a press release issued by Moody's Investors Service that downgraded the credit ratings on various debt instruments issued by certain of Vectren Corporation's wholly owned subsidiaries.

Item 5. Other Events
Item 7. Exhibits
99.1 - Press Release - Moody's Investors Service
99.2 - Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

SCHEDULE II

Vectren Utility Holdings, Inc. and Subsidiary Companies

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning Of Year	Charged to Expenses	Charged to Other Accounts	Deductions from Reserves, Net	Balance at End of Year
(In millions)					
VALUATION AND QUALIFYING ACCOUNTS: AS RESTATED					
Year 2002 - Accumulated provision for uncollectible accounts	$ 5.1	$ 11.7	$ -	$ 11.3	$ 5.5
Year 2001 - Accumulated provision for uncollectible accounts	$ 5.1	$ 15.1	$ -	$ 15.1	$ 5.1
Year 2000 - Accumulated provision for uncollectible accounts	$ 3.9	$ 6.6	$ 0.1	$ 5.5	$ 5.1
OTHER RESERVES:					
Year 2002 - Reserve for merger and integration charges	$ 0.4	$ -	$ -	$ 0.4	$ -
Year 2001 - Reserve for merger and integration charges	$ 1.8	$ -	$ -	$ 1.4	$ 0.4
Year 2000 - Reserve for merger and integration charges	$ -	$ 19.3	$ -	$ 17.5	$ 1.8
Year 2002 - Reserve for restructuring costs	$ 4.3	$ -	$ -	$ 0.7	$ 3.6
Year 2001 - Reserve for restructuring costs	$ -	$ 9.2	$ -	$ 4.9	$ 4.3

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Amendment No. 1 on Form 10-K/A to the Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

VECTREN UTILITY HOLDINGS, INC.

Dated June 18, 2003

/S/ Niel C. Ellerbrook

Niel C. Ellerbrook,
Chairman and Chief Executive Officer, Director

INDEX TO EXHIBITS

2. Plan Of Acquisition, Reorganization, Arrangement, Liquidation Or Succession

2.1 Asset Purchase Agreement dated December 14,1999 between Indiana Energy, Inc. and The Dayton Power and Light Company and Number-3CHK with a commitment letter for a 364-Day Credit Facility dated December 16,1999. (Filed and designated in Current Report on Form 8-K dated December 28, 1999, File No. 1-9091, as Exhibit 2 and 99.1.)

3. Articles Of Incorporation And By-Laws

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

3.2 Bylaws of Vectren Utility Holdings, Inc. (Filed and designated in Registration Statement on Amendment 3 to Form 10, File No. 1-16739, as Exhibit 3.2)

4. Instruments Defining The Rights Of Security Holders, Including Indentures

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

Exhibit 4(a).) July 1, 1999. (Filed and designated in Form 10-Q, dated August 16, 1999, File No. 1-3553, as Exhibit 4(a).) March 1, 2000. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 4.1.)

4.2 Indenture dated February 1, 1991, between Indiana Gas and U.S. Bank Trust National Association (formerly know as First Trust National Association, which was formerly know as Bank of America Illinois, which was formerly know as Continental Bank, National Association. Inc.'s. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494.); First Supplemental Indenture thereto dated as of February 15, 1991. (Filed and designated in Current Report on Form 8-K filed February 15, 1991, File No. 1-6494, as Exhibit 4(b).); Second Supplemental Indenture thereto dated as of September 15, 1991, (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File No. 1-6494, as Exhibit 4(b).); Third supplemental Indenture thereto dated as of September 15, 1991 (Filed and designated in Current Report on Form 8-K filed September 25, 1991, File No. 1-6494, as Exhibit 4(c).); Fourth Supplemental Indenture thereto dated as of December 2, 1992, (Filed and designated in Current Report on Form 8-K filed December 8, 1992, File No. 1-6494, as Exhibit 4(b).); Fifth Supplemental Indenture thereto dated as of December 28, 2000, (Filed and designated in Current Report on Form 8-K filed December 27, 2000, File No. 1-6494, as Exhibit 4.)

4.3 Indenture dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.1); First Supplemental Indenture, dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.2); Second Supplemental Indenture, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 29, 2001, File No. 1-16739, as Exhibit 4.1).

10. Material Contracts

10.1 Agreement, dated, January 30, 1968, for Unit No. 4 at the Warrick Power Plant of Alcoa Generating Corporation ("Alcoa"), between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-29653 as Exhibit 4(d)-A.)

10.2 Letter of Agreement, dated June 1, 1971, and Letter Agreement, dated June 26, 1969, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-41209 as Exhibit 4(e)-2.)

10.3 Letter Agreement, dated April 9, 1973, and Agreement dated April 30, 1973, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-53005 as Exhibit 4(e)-4.)

10.4 Electric Power Agreement (the "Power Agreement"), dated May 28, 1971, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-41209 as Exhibit 4(e)-1.)

10.5 Second Supplement, dated as of July 10, 1975, to the Power Agreement and Letter Agreement dated April 30, 1973 - First Supplement. (Filed and designated in Form 10-K for the fiscal year 1975, File No. 1-3553, as Exhibit 1(e).)

10.6 Third Supplement, dated as of May 26, 1978, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1978 as Exhibit A-1.)

10.7 Letter Agreement dated August 22, 1978 between Southern Indiana Gas and Electric Company and Alcoa, which amends Agreement for Sale in an Emergency of Electrical Power and Energy Generation by Alcoa and Southern Indiana Gas and Electric Company dated June 26, 1979. (Filed and designated in Form 10-K for the fiscal year 1978, File No. 1-3553, as Exhibit A-2.)

10.8 Fifth Supplement, dated as of December 13, 1978, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1979, File No. 1-3553, as Exhibit A-3.)

10.9 Sixth Supplement, dated as of July 1, 1979, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1979, File No. 1-3553, as Exhibit A-5.)

10.10 Seventh Supplement, dated as of October 1, 1979, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1979, File No. 1-3553, as Exhibit A-6.)

10.11 Eighth Supplement, dated as of June 1, 1980 to the Electric Power Agreement, dated May 28, 1971, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Form 10-K for the fiscal year 1980, File No. 1-3553, as Exhibit (20)-1.)

10.12 Amendment Agreement, dated March 3, 2001, between Alcoa Power Generating Inc. and Southern Indiana Gas and Electric Company. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.12.)

10.13 Summary description of Southern Indiana Gas and Electric Company's nonqualified Supplemental Retirement Plan (Filed and designated in Form 10-K for the fiscal year 1992, File No. 1-3553, as Exhibit 10-A-17.)

10.14 Southern Indiana Gas and Electric Company 1994 Stock Option Plan (Filed and designated in Southern Indiana Gas and Electric Company's Proxy Statement dated February 22, 1994, File No. 1-3553, as Exhibit A.)

10.15 Southern Indiana Gas and Electric Company's nonqualified Supplemental Retirement Plan as amended, effective April 16, 1997. (Filed and designated in Form 10-K for the fiscal year 1997, File No. 1-3553, as Exhibit 10.29.)

10.16 Vectren Corporation Retirement Savings Plan (amended and restated effective January 1, 2002). (Filed and designated in Form 10-Q for the quarterly period ended September 30, 2002, File No. 1-15467, as Exhibit 10.1.)

10.17 Vectren Corporation Combined Non-Bargaining Retirement Plan. (Filed and designated in Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15467, as Exhibit 99.2.)

10.18 Indiana Energy, Inc. Unfunded Supplemental Retirement Plan for a Select Group of Management Employees as amended and restated effective December 1, 1998. (Filed and designated in Form 10-Q for the quarterly period ended December 31, 1998, File No. 1-9091, as Exhibit 10-G.)

10.19 Indiana Energy, Inc. Nonqualified Deferred Compensation Plan effective January 1, 1999. (Filed and designated in Form 10-Q for the quarterly period ended December 31, 1998, File No. 1-9091, as Exhibit 10-H.)

10.20 Formation Agreement among Indiana Energy, Inc., Indiana Gas Company, Inc., IGC Energy, Inc., Indiana Energy Services, Inc., Citizens Gas & Coke Utility, Citizens Energy Services Corporation and ProLiance Energy, LLC, effective March 15, 1996. (Filed and designated in Form 10-Q for the quarterly period ended March 31, 1996, File No. 1-9091, as Exhibit 10-C.)

10.21 Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC, effective March 15, 1996, for services to begin April 1, 1996. (Filed and designated in Form 10-Q for the quarterly period ended March 31, 1996, File No. 1-6494, as Exhibit 10-C.)

10.22 Amended appendices to the Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC effective November 1, 1998. (Filed and designated in Form 10-Q for the quarterly period ended March 31, 1999, File No. 1-6494, as Exhibit 10-A.)

10.23 Amended appendices to the Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC effective November 1, 1999. (Filed and designated in Form 10-K for the fiscal year ended September 30, 1999, File No. 1-6494, as Exhibit 10-V.)

10.24 Gas Sales and Portfolio Administration Agreement between Vectren Energy Delivery of Ohio and ProLiance Energy, LLC, effective October 31, 2000, for services to begin November 1, 2000. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10-24.)

10.25 Indiana Energy, Inc. Executive Restricted Stock Plan as amended and restated effective October 1, 1998. (Filed and designated in Form 10-K for the fiscal year ended September 30, 1998, File No. 1-9091, as Exhibit 10-O.)

10.26 Amendment to Indiana Energy, Inc. Executive Restricted Stock Plan effective December 1, 1998. (Filed and designated in Form 10-Q for the quarterly period ended December 31, 1998, File No. 1-9091, as Exhibit 10-I.)

10.27 Indiana Energy, Inc. Director's Restricted Stock Plan as amended and restated effective May 1, 1997. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 1997, File No. 1-9091, as Exhibit 10-B.)

10.28 First Amendment to Indiana Energy, Inc. Directors' Restricted Stock Plan, effective December 1, 1998. (Filed and designated in Form 10-Q for the quarterly period ended December 31, 1998, File No. 1-9091, as Exhibit 10-J.)

10.29 Second Amendment to Indiana Energy, Inc. Directors Restricted Stock Plan, renamed the Vectren Corporation Directors Restricted Stock Plan effective October 1, 2000. (Filed and designated in Form 10-K for the year ended December 31, 2000, File No. 1-15467, as Exhibit 10-34.)

10.30 Third Amendment to Indiana Energy, Inc. Directors Restricted Stock Plan, renamed the Vectren Corporation Directors Restricted Stock Plan effective March 28, 2001. (Filed and designated in Form 10-K for the year ended December 31, 2000, File No. 1-15467, as Exhibit 10-35.)

10.31 Vectren Corporation At Risk Compensation Plan effective May 1, 2001. (Filed and designated in Vectren Corporation's Proxy Statement dated March 16, 2001, File No. 1-15467, as Appendix B.)

10.32 Vectren Corporation Non-Qualified Deferred Compensation Plan, as amended and restated effective January 1, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.32.)

10.33 Vectren Corporation Employment Agreement between Vectren Corporation and Niel C. Ellerbrook dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.1.)

10.34 Vectren Corporation Employment Agreement between Vectren Corporation and Andrew E. Goebel dated as of March 31, 2000 (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.2.)

10.35 Vectren Corporation Employment Agreement between Vectren Corporation and Jerome A. Benkert, Jr. dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.3.)

10.36 Vectren Corporation Employment Agreement between Vectren Corporation and Ronald E. Christian dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.5.)

10.37 Vectren Corporation Employment Agreement between Vectren Corporation and Timothy M. Hewitt dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.6.)

10.38 Vectren Corporation Retirement Agreement between Vectren Corporation and Timothy M. Hewitt dated as of May 31, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.39.)

10.39 Vectren Corporation Employment Agreement between Vectren Corporation and J. Gordon Hurst dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.7.)

10.40 Vectren Corporation Retirement Agreement between Vectren Corporation and J. Gordon Hurst dated as of May 31, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.41.)

10.41 Vectren Corporation Employment Agreement between Vectren Corporation and Richard G. Lynch dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.8.)

10.42 Vectren Corporation Employment Agreement between Vectren Corporation and William S. Doty dated as of April 30, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.43.)

10.43 Vectren Corporation Retirement Agreement between Vectren Corporation and Thomas J. Zabor dated as of May 31, 2001. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.44.)

21. Subsidiaries Of The Company

The list of the Company's significant subsidiaries was filed and designated in Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-16739, as Exhibit 21.1.

99. Additional Exhibits

99.1 Vectren Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934, but not including the Compensation Committee Report and Performance Graph. (Filed herewith.)

99.2 Agreement and Plan of Merger dated as of June 11,1999 among Indiana Energy, Inc., SIGCORP, Inc. and Vectren Corporation (the "Merger Agreement "). (Filed and designated in Form S-4 to (No. 333-90763) filed on November 12, 1999, File No. 1-15467, as Exhibit 2.)

99.3 Amendment No.1 to the Merger Agreement dated December 14, 1999 (Filed and designated in Current Report on Form 8-K filed December 16, 1999, File No. 1-09091, as Exhibit 2.)

99.4 Amended and Restated Articles of Incorporation of Vectren Corporation effective March 31, 2000. (Filed and designated in Current Report on Form 8-K filed April 14, 2000, File No. 1-15467, as Exhibit 4.1.)

99.5 Amended and Restated Code of By-Laws of Vectren Corporation as of February 26, 2003. (Filed and designated in Form 10-K for the year ended December 31, 2002, File No. 1-15467, as Exhibit 3.2

99.6 Shareholders Rights Agreement dated as of October 21, 1999 between Vectren Corporation and Equiserve Trust Company, N.A., as Rights Agent. (Filed and designated in Form S-4 (No. 333-90763), filed November 12. 1999, File No. 1-15467, as Exhibit 4.)

99.7 Certifications Pursuant to Section 906 of the Sarbanes-Oxlet Act of 2002. (Filed Herewith.)

99.8 Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. (Filed Herewith.)

99.9 Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. (Filed Herewith.)

Vectren Utility Holdings, Inc.
2002 Form 10-K/A
Attached Exhibits

The following Exhibits were filed electronically with the SEC with this filing. See Page 85 of this amendment to the annual report on Form 10-K/A for a complete list of exhibits.

Exhibit Number	Document
99.1	Vectren Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934.
99.7	Certifications Pursuant to Section 906 of the Sarbanes-Oxlet Act of 2002.
99.8	Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.9	Chief Financial Officer Certification Pursuant to Section 302 of

the Sarbanes-Oxley Act of 2002.