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

# FORM 10-K

(Mark One)

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

**For the fiscal year ended December 31, 2003**

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: **1-15467**

# VECTREN CORPORATION

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **INDIANA** | **35-2086905** |
| (State or other jurisdiction of incorporation or organization) | (IRS Employer Identification No.) |
| **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 |
|---|---|
| **Common – Without Par** | **New York Stock Exchange** |

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2003, was $1,691,200,174.

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** | **75,792,899** | **January 30, 2004** |

**Documents Incorporated by Reference**

Certain information in the Company's definitive Proxy Statement for the 2004 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, not later than 120 days after the end of the fiscal year, 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 of dekatherms

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 gas transportation volumes

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## Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports free of charge 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: |
|---|---|---|
| P.O. Box 209 | (812) 491-4000 | Steven M. Schein |
| Evansville, Indiana 47702-0209 | | Vice President, Investor Relations |
| | | sschein@vectren.com |

## PART I

## ITEM 1. BUSINESS

### Description of the Business

Indiana Energy, Inc. (Indiana Energy) and SIGCORP, Inc. (SIGCORP) are the predecessor companies to Vectren Corporation. Indiana Energy, incorporated under Indiana law on October 24, 1985, was engaged in natural gas distribution, gas portfolio administrative services, and marketing of natural gas, electric power and related services. Indiana Energy had fourteen subsidiaries, including ten nonregulated direct or indirect subsidiaries, a not-for-profit foundation and three utility subsidiaries, as well as investments in four nonregulated joint ventures. SIGCORP, incorporated under Indiana law on October 19, 1994, was engaged in electric generation, transmission, and distribution, natural gas distribution, coal mining, and broadband communication services. SIGCORP had eleven wholly owned subsidiaries, including ten nonregulated subsidiaries.

Vectren Corporation (the Company or Vectren), an Indiana corporation, 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 that has been accounted for as a pooling-of-interests in accordance with APB Opinion No. 16 “Business Combinations” (APB 16).

The Company’s wholly owned subsidiary, Vectren Utility Holdings, Inc. (VUHI), serves as the intermediate holding company for its three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), formerly a wholly owned subsidiary of Indiana Energy, Southern Indiana Gas and Electric Company (SIGECO), formerly a wholly owned subsidiary of SIGCORP, and the Ohio operations. VUHI also has other assets that provide information technology and other services to the three utilities. 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.

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.

The Company is also involved in nonregulated activities in four primary business areas: Energy Marketing and Services, Coal Mining, Utility Infrastructure Services, and Broadband. Energy Marketing and Services markets natural gas and provides energy management services, including energy performance contracting services. Coal Mining mines and sells coal and generates IRS Code Section 29 investment tax credits relating to the production of coal-based synthetic fuels. Utility Infrastructure Services provides underground construction and repair, facilities locating, and meter reading services. Broadband invests in broadband communication services such as analog and digital cable television, high-speed Internet and data services, and advanced local and long distance phone services. In addition, the nonregulated group has other businesses that provide utility services, municipal broadband consulting, and retail products and services that invest in energy-related opportunities, real estate and leveraged leases. The nonregulated group supports the Company’s regulated utilities pursuant to service contracts by providing natural gas supply services, coal, utility infrastructure services, and other services.

**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 holds the natural gas distribution assets in Ohio 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 operations into three groups: 1) Utility Group, 2) Nonregulated Group, and 3) Corporate and Other Group. At December 31, 2003, the Company had $3.4 billion in total assets, with $2.9 billion (87%) attributed to the Utility Group, $0.4 billion (12%) attributed to the Nonregulated Group, and less than $0.1 billion (1%) attributed to the Corporate and Other Group. Net income for the year ended December 31, 2003, was $111.2 million, or $1.58 per share of common stock, with $85.6 million attributed to the Utility Group, $27.6 million attributed to the Nonregulated Group, and a net loss of $2.0 million attributed to the Corporate and Other Group. Net income for the year ended December 31, 2002, was $114.0 million, or $1.69 per share of common stock.

For further information, refer to Note 17 regarding the activities and assets of operating segments within these Groups, Note 18 regarding special charges in 2001, Note 4 regarding the extraordinary loss in 2001, and Note 15 regarding the cumulative effect of change in accounting principle in 2001 in the Company's consolidated financial statements included under "Item 8 Financial Statements and Supplementary Data".

Following is a more detailed description of the Utility Group and Nonregulated Group. The operations of the Corporate and Other Group are not significant.

## Utility Group

The Utility Group is comprised of Vectren Utility Holdings, Inc.'s operations, which consist of the Company's regulated operations (the Gas Utility Services and Electric Utility Services operating segments), and other operations that provide information technology and other support services to those regulated 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 to 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 includes the Company's power generating and marketing operations. The Utility Group's other operations are not significant.

### Gas Utility Services

At December 31, 2003, the Company supplied natural gas service to 972,230 Indiana and Ohio customers, including 887,891 residential, 80,292 commercial, and 4,047 industrial and other customers. This represents customer base growth of 0.6% compared to 2002.

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, 2003, natural gas revenues were approximately $1,112.3 million, of which residential customers accounted for 67%, commercial 25%, and industrial and other 8%, 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) were 209,344 MDth for the year ended December 31, 2003. Gas transported or sold to residential and commercial customers were 118,460 MDth representing 57% of throughput. Gas transported or sold to industrial and other contract customers were 90,884 MDth representing 43% of 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 has storage capacity at seven active underground gas storage fields, six liquefied petroleum air-gas manufacturing plants, and a propane cavern. The Company also contracts with ProLiance Energy, LLC (ProLiance or ProLiance Energy) to ensure availability of gas. ProLiance is an unconsolidated, nonregulated, energy marketing affiliate of Vectren and Citizens Gas and Coke Utility (Citizens Gas). (See the discussion of Energy Marketing & Services below and Note 3 in the Company's consolidated financial statements included in "Item 8 Financial Statements and Supplementary Data" regarding transactions with ProLiance). Purchased natural gas 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 1,775,657 MCF of gas per day can be delivered during peak demand periods from all sources and for all utilities.

Gas Purchases

In 2003, the Company purchased 118,684 MDth volumes of gas at an average cost of $6.36 per Dth, substantially all of which was purchased from ProLiance, which buys the gas as an agent. The average cost of gas per Dth purchased for the last five years was: $6.36 in 2003; $4.57 in 2002; $5.83 in 2001; $5.60 in 2000; and $3.58 in 1999.

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, 2003, the Company supplied electric service to 135,098 Indiana customers, including 117,868 residential, 17,054 commercial, and 176 industrial and other customers. This represents customer base growth of 0.8% compared to 2002. In addition, the Company is obligated to provide for firm power commitments to four 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, 2003, retail and firm wholesale electricity sales totaled 5,898,852 MWh, resulting in revenues of approximately $309.1 million. Residential customers accounted for 34% of 2003 revenues; commercial 27%; industrial and municipalities 37%; and other 2%. In addition, the Company sold 4,305,190 MWh through wholesale contracts in 2003, generating revenue, net of purchased power costs, of $26.5 million.

Generating Capacity

Installed generating capacity as of December 31, 2003, was rated at 1,351 MW. Coal-fired generating units provide 1,056 MW of capacity, and natural 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, in 2003, the Company had 32 MW available under firm contracts and 95 MW available under interruptible contracts. In October 2003, the Company executed a firm purchase supply contract for a maximum of 73MW for the peak cooling season months in each of the next three years.

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 has been, and may continue to 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 1999 through 2003 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

| Date of summer peak load | 8/27/2003 | 8/5/2002 | 7/31/2001 | 8/17/2000 | 7/6/1999 |
|---|---|---|---|---|---|
| Total load at peak [(1)] | 1,272 | 1,258 | 1,234 | 1,212 | 1,255 |
| | | | | | |
| Generating capability | 1,351 | 1,351 | 1,271 | 1,256 | 1,256 |
| Firm purchase supply | 32 | 82 | 82 | 75 | - |
| Interruptible contracts | 95 | 95 | 95 | 95 | 95 |
| Total power supply capacity | 1,478 | 1,528 | 1,448 | 1,426 | 1,351 |
| Reserve margin at peak | 16% | 21% | 17% | 18% | 8% |

(1) The total load at peak is increased 25 MW in 2003, 2002, 2001, and 1999 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 2002-2003 season of approximately 948 MW occurred on January 27, 2003, and was 11% higher than the previous winter peak load of approximately 854 MW which occurred on March 4, 2002.

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. Such generating capacity is included in firm purchase supply in the chart above.

Fuel Costs and Purchased Power

Electric generation for 2003 was fueled by coal (99.3%) and natural gas (0.7%). 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 the Company. Approximately 3.1 million tons of coal were purchased for generating electricity during 2003, of which substantially all was supplied by Vectren Fuels, Inc. from its mines and third party purchases. The average cost of coal consumed in generating electric energy for the years 1999 through 2003 follows:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| Avg. Cost Per | 2003 | 2002 | 2001 | 2000 | 1999 |
| Ton | $ 24.91 | $ 23.50 | $ 22.48 | $ 22.49 | $ 21.88 |
| MWh | 11.93 | 11.00 | 10.53 | 10.39 | 10.13 |

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 other wholesale customers. Volumes purchased in 2003 totaled 4,082,404 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 settlement of 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 regulated utility industry for the Company's regulated Indiana and Ohio operations.

## Nonregulated Group

The Company is involved in nonregulated activities in four primary business areas: Energy Marketing and Services, Coal Mining, Utility Infrastructure Services, and Broadband.

**Energy Marketing and Services**

The Energy Marketing and Services group relies heavily upon a customer focused, value added strategy. The group provides natural gas and fuel supply management services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions through ProLiance Energy, an unconsolidated affiliate of the Company and Citizens Gas. The Company contracted for all natural gas purchases through ProLiance in 2003. The group also focuses on performance-based energy contracting through Energy Systems Group, LLC (ESG). This service helps schools, hospitals, and other governmental and private institutions reduce their energy and maintenance costs by upgrading their facilities with energy-efficient equipment.

In June 2002, the integration of Vectren's wholly owned subsidiary SIGCORP Energy Services, LLC (SES) with ProLiance was completed. SES provided natural gas and related services to SIGECO and others prior to the integration. In exchange for the contribution of SES' net assets totaling $19.2 million, including cash of $2.0 million, Vectren's allocable share of ProLiance's profits and losses increased from 52.5% to 61%, consistent with Vectren's new ownership percentage. In March 2001, Vectren's allocable share of profits and losses increased from 50% to 52.5% when ProLiance began managing the Ohio operations' gas portfolio. Governance and voting rights remain at 50% for each member; and therefore, Vectren continues to account for its investment in ProLiance using the equity method of accounting.

At December 31, 2003, the Energy Marketing and Services group's natural gas marketing operations had 1,222 customers, up from 1,060 in 2002. ProLiance's revenue exceeded $2.2 billion in 2003.

Prior to April 2003, ESG was a consolidated venture between the Company and Citizens Gas with the Company owning two-thirds. In April 2003, the Company purchased the remaining interest in ESG for approximately $4 million.

**Coal Mining**

The Coal Mining group provides the mining and sale of coal to the Company's utility operations and to other third parties through its wholly owned subsidiary Vectren Fuels, Inc. The Coal Mining group also generates income tax credits through IRS Code Section 29 investment tax credits relating to the production of coal-based synthetic fuels through its 8.3% ownership in Pace Carbon Synfuels, LP (Pace Carbon). The Company's two coal mines produced 3.3 million tons in 2003, down from 3.5 million in 2002. The Company's investment in Pace Carbon is accounted for using the equity method of accounting.

**Utility Infrastructure Services**

Utility Infrastructure Services provides underground construction and repair of utility infrastructure services to the Company and to other gas, water, electric, and telecommunications companies as well as facilities locating and meter reading services through its investment in Reliant Services, LLC (Reliant) and Reliant's 100% ownership in Miller Pipeline, which was purchased by Reliant in 2000. Reliant is a 50% owned strategic alliance with an affiliate of Cinergy Corp. and is accounted for using the equity method of accounting.

**Broadband**

Broadband invests in broadband communication services such as cable television, high-speed Internet, and advanced local and long distance phone services. The Broadband group provides these services primarily to the greater Evansville area in southwestern Indiana. At December 31, 2003, there were over 27,000 residential customers yielding over 81,000 revenue generating units (up from 77,000 at the end of 2002) indicating multiple services being utilized by the same residential customer. At December 31, 2003, there were approximately 2,000 commercial customers.

The Company has an approximate 2% equity interest and a convertible subordinated debt investment in Utilicom Networks, LLC (Utilicom). Utilicom is a provider of bundled communication services focusing on last mile delivery to residential and commercial customers. The Company also has an approximate 19% equity interest in SIGECOM Holdings, Inc., which was formed by Utilicom to hold interests in SIGECOM, LLC (SIGECOM). SIGECOM provides broadband services to the greater Evansville, Indiana area.

Utilicom also plans to provide services to Indianapolis, Indiana and Dayton, Ohio. However, the funding of these projects has been delayed due to the continued difficult environment within the telecommunication capital markets, which has prevented Utilicom from obtaining debt financing on terms it considers acceptable. While the existing investors remain interested in the Indianapolis and Dayton projects, the Company is not required to make further investments and does not intend to proceed unless commitments are obtained to fully fund these projects. Franchising agreements have been extended in both locations.

The convertible subordinated debt investment totals $32.3 million, of which $30.1 million is convertible into Utilicom ownership at the Company's option or upon the event of a public offering of stock by Utilicom and $2.2 million is convertible into common equity interests in the Indianapolis and Dayton ventures at the Company's option. Upon conversion, the Company would have up to a 16% interest in Utilicom, assuming completion of all required funding, and up to a 31% interest in the Indianapolis and Dayton ventures.

**Other Businesses**

In addition to the nonregulated business groups previously discussed, the Other Businesses group invests in a portfolio of interests in gas and power storage, distributed generation projects, and similar energy-related businesses. Additional activities include:

- A retail unit, providing natural gas and other related products and services primarily in Ohio serving customers opting for choice among energy providers.
- A broadband consulting business.

Major investments at December 31, 2003, include Haddington Energy Partnerships, two partnerships both approximately 40% owned; and the wholly owned subsidiaries Southern Indiana Properties, Inc., Energy Realty, Inc., Vectren Retail, LLC, and Vectren Communications Services, Inc.

## Personnel

As of December 31, 2003, the Company and its consolidated subsidiaries had 1,858 employees, of which 884 are subject to collective bargaining arrangements.

In January 2004, the Company signed a five-year labor agreement, ending December 2008, with Local 1393 of the International Brotherhood of Electrical Workers and United Steelworkers of America locals 12213 and 7441. The agreement provides for annual wage increases of 3%, a multi-tiered health care plan in which the employees pay 12% to 16% of the premium, and pension enhancements for early retirees.

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 four-year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 2004. The 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 active gas storage fields located in Indiana covering 58,290 acres of land with an estimated ready delivery from storage capability of 5.2 BCF of gas with maximum peak day 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 33,000 MCF of manufactured gas per day. In addition to its company owned storage and propane capabilities, Indiana Gas has contracted for 17.2 BCF of storage with a maximum peak day delivery capability of 404,614 MCF per day. Indiana Gas has the ability to meet a total annual demand, utilizing all of its assets across various pipelines, of 131.1 BCF with a maximum peak day delivery capability of 1,068,740 MCF per day. Indiana Gas' gas delivery system includes 11,771 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 6.3 BCF of gas with maximum peak day delivery capabilities of 124,748 MCF per day. In addition to its company owned storage delivery capabilities, SIGECO has contracted for 0.5 BCF of storage with a maximum peak day delivery capability of 18,699 MCF per day. SIGECO has the ability to meet a total annual demand, utilizing all of its assets across various pipelines, of 28.4 BCF with a maximum peak day delivery capability of 228,943 MCF per day. SIGECO's gas delivery system includes 3,026 miles of distribution and transmission mains, all of which are located in Indiana.

The Ohio operations own and operate three liquefied petroleum (propane) air-gas manufacturing plants and a cavern for propane storage, all of which are located in Ohio. The plants and cavern can store 7.5 million gallons of propane, and the plants can manufacture for delivery 51,047 MCF of manufactured gas per day. In addition to its propane delivery capabilities, the Ohio operations have contracted for 13.1 BCF of storage with a maximum peak day delivery capability of 280,667 MCF per day. The Ohio operations have the ability to meet a total annual demand, utilizing all of its assets across various pipelines, of 57.9 BCF with a maximum peak day delivery capability of 477,974 MCF per day. The Ohio operations' gas delivery system includes 5,216 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, 2003, 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, 50 MW and Broadway Avenue Unit 2, 65 MW); two Northeast Gas Turbines located northeast of Evansville in Vanderburgh County, Indiana with a combined capacity of 20 MW; and a new 80 MW 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 830 circuit miles of 138,000 and 69,000 volt lines. The transmission system also includes 27 substations with an installed capacity of 4,235.9 megavolt amperes (Mva). The electric distribution system includes 3,224 pole miles of lower voltage overhead lines and 289 trench miles of conduit containing 1,622 miles of underground distribution cable. The distribution system also includes 92 distribution substations with an installed capacity of 1,901.7 Mva and 51,417 distribution transformers with an installed capacity of 2,368.6 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.

## Nonregulated Properties

Subsidiaries other than the utility operations have no significant properties other than the ownership and operation of coal mining property in Indiana and investments in real estate partnerships, leveraged leases, and notes receivable. The assets of the coal mining operations comprise approximately 3% percent of total assets.

## 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 13 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 regarding the Culley generating station's compliance with the Clean Air Act were substantially resolved during 2003.

## 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 COMPANY'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's common stock trades on the New York Stock Exchange under the symbol ''VVC.'' For each quarter in 2003 and 2002, the high and low sales prices for the Company's common stock as reported on the New York Stock Exchange and dividends paid are shown in the following table.

| | Cash | Common Stock Price Range | |
|---|---|---|---|
| **2003** | Dividend | High | Low |
| First Quarter | $ 0.275 | $ 24.50 | $ 19.70 |
| Second Quarter | 0.275 | 26.13 | 21.05 |
| Third Quarter | 0.275 | 25.02 | 22.25 |
| Fourth Quarter | 0.285 | 24.85 | 22.73 |
| | | | |
| **2002** | | | |
| First Quarter | $ 0.265 | $ 25.95 | $ 22.45 |
| Second Quarter | 0.265 | 26.10 | 23.10 |
| Third Quarter | 0.265 | 25.44 | 17.95 |
| Fourth Quarter | 0.275 | 25.00 | 21.05 |

On January 28, 2004, the board of directors declared a dividend of $0.285 per share, payable on March 1, 2004, to common shareholders of record on February 13, 2004.

As of January 30, 2004, there were 12,889 shareholders of record of the Company's common stock.

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

## ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data is derived from the Company's audited consolidated financial statements and should be read in conjunction with those financial statements and notes thereto contained in this Form 10-K. Operating revenues for the years ended December 31, 2002, through December 31, 1999, have been reclassified to reflect the adoption of EITF 03-11. Total assets as of December 31, 2002, also reflect a reclassification for the adoption of SFAS 143. See Note 15 and Note 2 to the consolidated financial statements for further information on the adoption of EITF 03-11 and SFAS 143, respectively, included under Item 8 "Financial Statements and Supplementary Data."

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| *(In millions, except per share data)* | 2003 | 2002 | 2001 [1] | 2000 [2,3] | 1999 |
| **Operating Data:** | | | | | |
| Operating revenues | $ 1,587.7 | $ 1,523.8 | $ 2,009.1 | $ 1,607.6 | $ 1,056.2 |
| Operating income | $ 199.4 | $ 211.3 | $ 127.9 | $ 131.7 | $ 160.8 |
| Income before extraordinary loss & cumulative effect of change in accounting principle | $ 111.2 | $ 114.0 | $ 59.3 | $ 72.0 | $ 90.7 |
| Net income | $ 111.2 | $ 114.0 | $ 52.7 | $ 72.0 | $ 90.7 |
| Average common shares outstanding | 70.6 | 67.6 | 66.7 | 61.3 | 61.3 |
| Fully diluted common shares outstanding | 70.8 | 67.9 | 66.9 | 61.4 | 61.4 |
| Basic earnings per share before extraordinary loss & cumulative effect of change in accounting principle | $ 1.58 | $ 1.69 | $ 0.89 | $ 1.18 | $ 1.48 |
| Basic earnings per share on common stock | $ 1.58 | $ 1.69 | $ 0.79 | $ 1.18 | $ 1.48 |
| Diluted earnings per share before extraordinary loss & cumulative effect of change in accounting principle | $ 1.57 | $ 1.68 | $ 0.89 | $ 1.17 | $ 1.48 |
| Diluted earnings per share on common stock | $ 1.57 | $ 1.68 | $ 0.79 | $ 1.17 | $ 1.48 |
| Dividends per share on common stock | $ 1.11 | $ 1.07 | $ 1.03 | $ 0.98 | $ 0.94 |
| **Balance Sheet Data:** | | | | | |
| Total assets | $ 3,353.4 | $ 3,136.5 | $ 2,878.7 | $ 2,943.7 | $ 1,980.5 |
| Long-term debt, net | $ 1,072.8 | $ 954.2 | $ 1,014.0 | $ 632.0 | $ 486.7 |
| Redeemable preferred stock | $ 0.2 | $ 0.3 | $ 0.5 | $ 8.1 | $ 8.2 |
| Common shareholders' equity | $ 1,071.7 | $ 869.9 | $ 839.3 | $ 733.4 | $ 709.8 |

(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 to reflect this decision, resulting in additional depreciation expense of approximately $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 ($8.0 million after tax).

The Company incurred restructuring charges of $19.0 million, ($11.8 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 $41.1 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 approximately $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 $52.5 million ($36.8 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.

**Executive Summary of Consolidated Results of Operations**

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions, except per share data)* | 2003 | 2002 | 2001 |
| Net income | $ 111.2 | $ 114.0 | $ 52.7 |
| Attributed to: | | | |
| Utility Group | $ 85.6 | $ 97.1 | $ 44.8 |
| Nonregulated Group | 27.6 | 19.0 | 12.1 |
| Corporate & other | (2.0) | (2.1) | (4.2) |
| Basic earnings per share | $ 1.58 | $ 1.69 | $ 0.79 |
| Attributed to: | | | |
| Utility Group | $ 1.21 | $ 1.44 | $ 0.67 |
| Nonregulated Group | 0.39 | 0.28 | 0.18 |
| Corporate & other | (0.02) | (0.03) | (0.06) |

### Results

For the year ended December 31, 2003, net income decreased $2.8 million, or $0.11 per share, when compared to 2002. The decline in earnings was principally due to the Utility Group's results which decreased $11.5 million, offset by increased earnings of $8.6 million from the Nonregulated Group. The decrease in earnings per share of $0.11 also reflects the impact of additional common shares outstanding resulting from an equity offering of approximately 7.4 million shares during 2003. The offering netted proceeds of approximately $163 million. The additional shares had the effect of reducing earnings per share as compared to 2002 by approximately $0.07.

The increase in Nonregulated Group earnings is due to increased earnings from the Energy Marketing and Services and Coal Mining Groups and a net gain recognized from business and investment divestitures. The decrease in Utility Group earnings was primarily due to increased operating expenses and the write-off of investments, partially offset by increased wholesale power margins and retail electric rate recovery related to NOx compliance expenditures and related operating expenses.

In 2002, consolidated net income increased $61.3 million, or $0.90 per share, when compared to 2001. The year ended December 31, 2001, included nonrecurring merger, integration, and restructuring costs and other nonrecurring items totaling $26.4 million after tax, or $0.40 per share. The increase also reflects improved Utility Group margins and lower operating costs. These resulted from favorable weather and lower gas prices and the related reduction in costs incurred in 2001. Also contributing to the increase was increased Nonregulated Group earnings from gas marketing operations.

The Utility Group generates revenue primarily from the delivery of natural gas and electric service to its customers. The primary source of cash flow for the Utility Group results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services. The results of the Utility Group are impacted by weather patterns in its service territory and general economic conditions both in its service territory as well as nationally.

The Nonregulated Group generates revenue or earnings from the provision of services to customers. The activities of the Nonregulated Group are closely linked to the utility industry, and the results of those operations are generally impacted by factors similar to those impacting the overall utility industry.

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

**Dividends**

Dividends declared for the year ended December 31, 2003, were $1.11 per share compared to $1.07 per share in 2002 and $1.03 per share in 2001. In October 2003, the Company's board of directors increased its quarterly dividend to $0.285 per share from $0.275 per share.

**Nonrecurring Items in 2001**

Merger & Integration Costs

Merger and integration related costs incurred during 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 and integration activities, management retired certain information systems in 2001. Accordingly, the useful lives of these assets were shortened to reflect this decision, resulting in additional depreciation expense of approximately $9.6 million for the year ended December 31, 2001. In total, merger and integration related costs incurred during 2001 were $12.4 million ($8.0 million after tax), or $0.12 per share. Merger and integration activities resulting from the 2000 merger forming Vectren were completed in 2001.

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 $11.8 million were expensed in June 2001 as a direct result of the restructuring plan. Additional charges of $7.2 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 $19.0 million ($11.8 million after tax), or $0.18 per share, in 2001. These charges were comprised of $10.9 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 $4.1 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.

Extraordinary Loss

In June 2001, the Company sold certain leveraged lease investments with a net book value of $59.1 million at a loss of $12.4 million ($7.7 million after tax), or $0.12 per share. Because of the transaction's significance and because the transaction occurred within two years of the effective date of the merger of Indiana Energy and SIGCORP, which was accounted for as a pooling-of-interests, APB 16 requires the loss on disposition of these investments to be treated as extraordinary. Proceeds from the sale of $46.7 million were used to retire short-term borrowings.

Cumulative Effect of Change in Accounting Principle

Resulting from the adoption of SFAS 133, certain contracts in the power marketing operations and gas 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), or $0.02 per share, recorded as a cumulative effect of change in accounting principle in the Consolidated Statements of Income. The majority of this gain results from the Company's power marketing operations.

**Detailed Discussion of Results of Operations**

Following is a more detailed discussion of the results of operations of the Company's Utility Group and Nonregulated Group. The detailed results of operations for the Utility Group and Nonregulated Group are presented and analyzed before the reclassification and elimination of certain intersegment transactions necessary to consolidate those results into the Company's Consolidated Statements of Income. The operations of the Corporate and Other Group are not significant.

## Results of Operations of the Utility Group

The Utility Group is comprised of Vectren Utility Holdings, Inc.'s operations, which consist of the Company's regulated operations (the Gas Utility Services and Electric Utility Services operating segments), and other operations that provide information technology and other support services to those regulated operations. Gas Utility Services provides natural gas distribution and transportation services in nearly two-thirds of Indiana and to west central Ohio. Electric Utility Services provides electricity primarily to southwestern Indiana, and includes the Company's power generating and marketing operations. The results of operations of the Utility Group before certain intersegment eliminations and reclassifications for the years ended December 31, 2003, 2002, and 2001, follow:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions, except per share data)* | 2003 | 2002 | 2001 |
| OPERATING REVENUES | | | |
| Gas utility | $ 1,112.3 | $ 908.0 | $ 1,019.6 |
| Electric utility | 335.7 | 328.6 | 308.5 |
| Other | 0.8 | 0.3 | 0.2 |
| **Total operating revenues** | **1,448.8** | **1,236.9** | **1,328.3** |
| OPERATING EXPENSES | | | |
| Cost of gas sold | 762.5 | 570.8 | 708.9 |
| Fuel for electric generation | 86.5 | 81.6 | 74.4 |
| Purchased electric energy | 16.2 | 16.8 | 14.2 |
| Other operating | 210.1 | 198.6 | 212.1 |
| Merger & integration costs | - | - | 2.8 |
| Restructuring costs | - | - | 15.0 |
| Depreciation & amortization | 117.9 | 110.7 | 117.9 |
| Taxes other than income taxes | 56.6 | 50.7 | 51.6 |
| Total operating expenses | 1,249.8 | 1,029.2 | 1,196.9 |
| **OPERATING INCOME** | **199.0** | **207.7** | **131.4** |
| OTHER INCOME (EXPENSE) | | | |
| Other – net | 4.8 | 7.1 | 5.6 |
| Equity in losses of unconsolidated affiliates | (0.5) | (1.8) | (0.5) |
| Total other income | 4.3 | 5.3 | 5.1 |
| Interest expense | 66.1 | 69.1 | 70.7 |
| **INCOME BEFORE INCOME TAXES** | **137.2** | **143.9** | **65.8** |
| Income taxes | 51.6 | 46.8 | 21.3 |
| Preferred dividend requirement of subsidiary | - | - | 0.8 |
| **INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE** | 85.6 | 97.1 | 43.7 |
| Cumulative effect of change in accounting principle - net of tax | - | - | 1.1 |
| **NET INCOME** | **$ 85.6** | **$ 97.1** | **$ 44.8** |
| **BASIC EARNINGS PER SHARE** | **$ 1.21** | **$ 1.44** | **$ 0.67** |

In 2003, Utility Group earnings were $85.6 million as compared to $97.1 million in 2002 and $44.8 million in 2001. The $11.5 million decrease occurring in 2003 compared to 2002 was primarily due to increased operating expenses and the write-off of investments, partially offset by increased wholesale power margins and retail electric rate recovery related to NOx compliance expenditures and related operating expenses.

Utility Group earnings increased $52.3 million in 2002 compared to 2001. The year ended December 31, 2001, included nonrecurring merger, integration, and restructuring costs and other nonrecurring items totaling $15.9 million after tax. The increase also reflects improved margins and lower operating costs. These resulted from favorable weather and lower gas prices and the related reduction in costs incurred in 2001. Weather increased utility earnings by an estimated $11 million.

Throughout this discussion, the terms Gas Utility margin and Electric Utility margin are used. Gas Utility margin and Electric Utility margin could be considered non-GAAP measures of income. Gas Utility margin is calculated as *Gas utility revenues* less the *Cost of gas sold*. Electric Utility margin is calculated as *Electric utility revenues* less *Fuel for electric generation* and *Purchased electric energy*. These measures exclude *Other operating expenses*, *Depreciation and amortization*, *Taxes other than income taxes, Merger and integration costs,* and *Restructuring costs,* which are included in the calculation of operating income. The Company believes Gas Utility and Electric Utility margins are better indicators of relative contribution than revenues since gas prices and fuel costs can be volatile and are generally collected on a dollar for dollar basis from customers. Margins should not be considered an alternative to, or a more meaningful indicator of operating performance than, operating income or net income as determined in accordance with accounting principles generally accepted in the United States.

**Significant Fluctuations**

Utility Group Margin

Margin generated from the sale of natural gas and electricity to residential and commercial customers is seasonal and impacted by weather patterns in its service territory. Margin generated from sales to industrial and other contract customers is impacted by overall economic conditions. In general, margin is not sensitive to variations in gas or fuel costs. It is, however, impacted by the collection of state mandated taxes which fluctuate with gas costs and also some level of fluctuation in volumes sold. Electric generating asset optimization activities are primarily affected by market conditions, the level of excess generating capacity, and electric transmission availability. Following is a discussion and analysis of margin generated from regulated utility operations.

*Gas Utility Margin (Gas Utility Revenues less Cost of Gas Sold)*
Gas Utility margin and throughput by customer type follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| Residential | $ 225.3 | $ 217.1 | $ 201.9 |
| Commercial | 65.0 | 65.5 | 57.7 |
| Contract | 50.5 | 50.5 | 48.4 |
| Other | 9.0 | 4.1 | 2.7 |
| Total gas utility margin | $ 349.8 | $ 337.2 | $ 310.7 |
| Sold & transported volumes in MMDth: | | | |
| To residential & commercial customers | 118.5 | 111.9 | 102.2 |
| To contract customers | 90.8 | 95.8 | 97.2 |
| Total throughput | 209.3 | 207.7 | 199.4 |

Gas Utility margin for the year ended December 31, 2003, of $349.8 million increased $12.6 million, or 4%, compared to 2002. It is estimated that weather near normal for the year and 6% cooler than the prior year, contributed $8 million in increased residential and commercial margin and was the primary contributor to increased throughput. The remaining increase is primarily attributable to $4.5 million in higher utility receipts and excise taxes on higher gas costs and volumes sold and $1.8 million in recovery of Ohio customer choice implementation costs. These increases are partially offset by the negative effect of high gas prices on customer usage.

Gas Utility margin for the year ended December 31, 2002, of $337.2 million increased $26.5 million, or 9%, compared to 2001. 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 one percent also contributed. It is estimated that weather contributed $10 million to the increase in Gas Utility margin, 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 effect of cooler weather was the primary factor driving an overall 4% increase in total throughput.

As noted above, gas cost fluctuations have impacted customer usage during the years ended December 31, 2003, 2002, and 2001. The average cost per dekatherm of gas purchased in those years was $6.36 in 2003, $4.57 in 2002, and $5.83 in 2001.

*Electric Utility Margin (Electric Utility Revenues less Fuel for Electric Generation and Purchased Electric Energy)*
Electric Utility margin by revenue type follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| Residential & commercial | $ 141.1 | $ 145.7 | $ 134.4 |
| Industrial | 53.5 | 54.9 | 49.6 |
| Municipalities & other | 20.1 | 16.9 | 16.8 |
| Total retail & firm wholesale | 214.7 | 217.5 | 200.8 |
| Asset optimization | 18.3 | 12.7 | 19.1 |
| Total electric utility margin | $ 233.0 | $ 230.2 | $ 219.9 |

*Retail & Firm Wholesale Margin*
For the year ended December 31, 2003, margin from serving native load and firm wholesale customers was $214.7 million, a decrease of $2.8 million when compared to 2002. It is estimated that summer weather 19% cooler than normal and 34% cooler than last year caused an $8 million decrease in residential and commercial margin. The estimated effect of weather was partially offset by a $7.1 million increase in retail electric rates related to recovery of NOx compliance expenditures and related operating expenses. A slowly recovering economy continued to negatively impact industrial sales which decreased $1.4 million compared to 2002. As a result primarily of the mild weather and slow economic conditions, retail and firm wholesale volumes sold decreased 5% to 5.90 GWh in 2003 compared to 6.19 GWh in 2002. Volumes sold in 2001 were 5.82 GWh. The current year decrease in native load and firm wholesale margin has been offset by increased optimization margin as more fully described below.

For the year ended December 31, 2002, margin from serving native load and firm wholesale customers increased $16.7 million or 8%, when compared to 2001. The increase results primarily from the effect on residential and commercial sales of cooling weather considerably warmer than the prior year. Weather in 2002 was 27% warmer than 2001 and 23% warmer than normal. In addition to weather, 2002 was positively affected by increased industrial and other wholesale volumes and rate recovery related to 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, native load and firm wholesale volumes sold increased 6%. It is estimated that weather contributed $7 million to the increase in electric utility margin, and the increased industrial and other wholesale volumes and the NOx recovery rider contributed $8 million.

*Margin from Asset Optimization Activities*
Periodically, generation capacity is in excess of that needed to serve native load and firm wholesale customers. The Company markets this unutilized capacity to optimize the return on its owned generation assets. Substantially all of these contracts are integrated with portfolio requirements around power supply and delivery and are short-term purchase and sale transactions that expose the Company to limited market risk.

Following is a reconciliation of asset optimization activity:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| Beginning of Year Net Asset Optimization Position | $ (0.7) | $ 3.3 | $ - |
| Statement of Income Activity | | | |
| Cumulative effect at adoption of SFAS 133 | - | - | 1.8 |
| Mark-to-market gains (losses) recognized | 0.7 | (3.6) | 1.5 |
| Realized gains recognized | 17.6 | 16.3 | 17.6 |
| Net activity in electric utility margin | 18.3 | 12.7 | 19.1 |
| Net cash received & other adjustments | (18.0) | (16.7) | (17.6) |
| End of Year Net Asset Optimization Position | $ (0.4) | $ (0.7) | $ 3.3 |
| Included in: | | | |
| *Prepayments & other current assets* | $ 2.4 | $ 3.5 | $ 6.1 |
| *Accrued liabilities* | (2.8) | (4.2) | (2.8) |

For the years ended December 31, 2003, 2002, and 2001, volumes sold into the wholesale market were 4.3 GWh, 10.7 GWh, and 3.4 GWh respectively, while volumes purchased were 4.1 GWh in 2003, 10.3 GWh in 2002, and 2.9 GWh in 2001. A portion of volumes purchased in the wholesale market is used to serve native load and firm wholesale customers, and in 2003, greater amounts of purchased power have been required for native load due to scheduled outages, which has reduced capacity available for optimization. Additionally, volumes sold and purchased were lower in 2003 compared to 2002 due to a shorter term focus in hedging and optimization strategies. While volumes both sold and purchased in the wholesale market have decreased during 2003, margin from optimization activities has increased compared to 2002 due primarily to price volatility. Despite the increased volumes in 2002, margins were lower in 2002 compared to 2001 due to reduced price volatility.

In July 2003, the EITF released EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3" (EITF 03-11). EITF 03-11 states that determining whether realized gains and losses on physically settled derivative contracts should be reported in the Statement of Income on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The EITF contains a presumption that net settled derivative contracts should be reported net in the Statement of Income. The Company adopted EITF 03-11 as required on October 1, 2003.

After considering the facts and circumstances relevant to the asset optimization portfolio, the Company believes presentation of these optimization activities on a net basis is appropriate and has reclassified purchase contracts and mark-to-market activity related to optimization activities from *Purchased electric energy* to *Electric utility revenues*. Prior year financial information has also been reclassified to conform to this net presentation.

Following is information regarding asset optimization activities included in *Electric utility revenues* and *Fuel for electric generation* in the Statements of Income.

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| Activity related to: | | | |
| Sales contracts | $ 152.8 | $ 302.8 | $ 101.4 |
| Purchase contracts | (127.0) | (275.9) | (74.3) |
| Mark-to-market gains (losses) | 0.7 | (3.6) | 1.5 |
| Net asset optimization revenue | 26.5 | 23.3 | 28.6 |
| Fuel for electric generation | (8.2) | (10.6) | (9.5) |
| Asset optimization margin | $ 18.3 | $ 12.7 | $ 19.1 |

Utility Group Operating Expenses

*Other Operating*
For the year ended December 31, 2003, other operating expenses increased $11.5 million compared to 2002. The increase is principally caused by increased distribution, plant, and transmission operating expenses; power plant and other maintenance; customer service initiatives; higher insurance premiums; and prior year insurance recoveries. In addition, operating expenses reflect $1.8 million in amortization of Ohio choice implementation costs, which are recovered through increased gas utility margin. The increase in operating expenses was partially offset by the impact of an Ohio regulatory order. The order allows the deferral and recovery of uncollectible accounts expense to the extent it differs from the level included in base rates. The Company estimated the difference to approximate $4 million in excess of that included in base rates in 2003.

Other operating expenses decreased $13.5 million for the year ended December 31, 2002, when compared to 2001. The decrease results primarily from 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 of certain maintenance costs incurred in 2001 also contributed to the decrease.

*Depreciation & Amortization*
For the year ended December 31, 2003, depreciation and amortization increased $7.2 million compared to 2002 due to additions to utility plant. Increased depreciation expense reflects depreciation of utility plant placed into service including a full year for a gas-fired peaker unit, expenditures for implementing a choice program for Ohio gas customers, customer system upgrades, and other upgrades to existing transmission and distribution facilities.

Depreciation and amortization decreased $7.2 million for the year ended December 31, 2002, when compared to 2001. The decrease results from $9.6 million of expense recognized in 2001 related to assets which had useful lives shortened as a result of the merger. The discontinuance of goodwill amortization as required by SFAS 142, which approximated $4.9 million in 2001, also contributed to the decrease. These decreases were offset somewhat by depreciation of utility plant and non-utility property additions.

*Taxes Other Than Income Taxes*
Taxes other than income taxes increased $5.9 million in 2003 compared to 2002. Higher utility receipts and excise taxes of $4.5 million were recognized in 2003 due to higher gas prices and more volumes sold compared to 2002. The remaining increase results principally from higher property taxes.

Taxes other than income taxes decreased $0.9 million in 2002 compared to 2001 as a result of lower revenues subject to the Indiana utility receipts tax.

Utility Group Other Income (Expense)

*Other - net*
Other - net decreased $2.3 million in 2003 compared to 2002 and increased $1.5 million in 2002 compared to 2001. The 2003 decrease is primarily due to the $3.9 million write-off of notes receivable and preferred equity investments in BABB International (BABB), an entity that processed fly ash into building materials. The 2002 increase results primarily from gains recognized from the sale of excess emission allowances and other assets.

*Equity in Losses of Unconsolidated Affiliates*
Equity in losses of unconsolidated affiliates increased $1.3 million in 2002 compared to 2001 principally due to increased losses and increased preferred ownership in BABB. The smaller loss recognized in 2003 results from the write-off of the BABB investment.

Utility Group Interest Expense

Interest expense decreased $3.0 million in 2003 compared to 2002 and decreased $1.6 million in 2002 compared to 2001. The 2003 decrease reflects the impact of permanent financing completed in the third quarter of 2003. Lower average interest rates on adjustable rate debt also contributed to the decreases in 2003 and 2002.

Utility Group Income Taxes

For the year ended December 31, 2003, federal and state income taxes increased $4.8 million in 2003 compared to 2002 and increased $25.5 million in 2002 compared to 2001. The 2003 increase results primarily from an increased effective tax rate that reflects an increase in the Indiana state income tax rate from 4.5 % to 8.5% and other changes in the effective tax rate recognized in 2002. The increase in 2002 compared to 2001 is principally due to higher pre-tax earnings.

**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 oxide (NOx). 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 with which to comply.

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 .141 lbs./MMBTU by May 31, 2004, (the compliance date). This is a 65% reduction in emission levels.

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 currently be the most effective method of reducing NOx emissions where high removal efficiencies are required.

The IURC has issued orders that approve:

- the Company's project to achieve environmental compliance by investing in clean coal technology;
- a total capital cost investment for this project up to $244 million (excluding AFUDC), subject to periodic review of the actual costs incurred;
- a mechanism whereby, prior to an electric base rate case, the Company may recover through a rider that is updated every six months, an 8 percent return on its weighted capital costs for the project; and
- ongoing recovery of operating costs, including depreciation and purchased emission allowances through a rider mechanism, related to the clean coal technology once the facility is placed into service.

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 is consistent with amounts approved in the IURC's orders and is expected to be expended during the 2001-2006 period. Through December 31, 2003, $145.2 million has been expended. After the equipment is installed and operational, related annual operating expenses, including depreciation expense, are estimated to be between $24 million and $27 million. A portion of those expenses began in October 2003 when the Culley SCR became operational. The 8 percent return on capital investment approximates the return authorized in the Company's last electric rate case in 1995 and includes a return on equity.

The Company expects to achieve timely compliance as a result of the project. Construction of the first SCR at Culley was placed into service in October 2003, and construction of the Warrick 4 and Brown SCR's is proceeding on schedule. 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 was filed in the U.S. District Court for the Southern District of Indiana. The USEPA alleged 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 alleged that the modifications to the Culley Generating Station required SIGECO to begin complying with federal new source performance standards at its Culley Unit 3. The USEPA also issued an administrative notice of violation to SIGECO making the same allegations, but alleging that violations began in 1977.

On June 6, 2003, SIGECO, the Department of Justice (DOJ), and the USEPA announced an agreement that would resolve the lawsuit. The agreement was embodied in a consent decree filed in U.S. District Court for the Southern District of Indiana. The mandatory public comment period has expired, and no comments were received. The Court entered the consent decree on August 13, 2003.

Under the terms of the agreement, the DOJ and USEPA have agreed to drop all challenges of past maintenance and repair activities at the Culley coal-fired units. In reaching the agreement, SIGECO did not admit to any allegations in the government's complaint, and SIGECO continues to believe that it acted in accordance with applicable regulations and conducted only routine maintenance on the units. SIGECO has entered into this agreement to further its continued commitment to improve air quality and avoid the cost and uncertainties of litigation.

Under the agreement, SIGECO has committed to:

- either repower Culley Unit 1 (50 MW) with natural gas, which would significantly reduce air emissions from this unit, and equip it with SCR control technology for further reduction of nitrogen oxide, or cease operation of the unit by December 31, 2006;
- operate the existing SCR control technology recently installed on Culley Unit 3 (287 MW) year round at a lower emission rate than that currently required under the NOx SIP Call, resulting in further nitrogen oxide reductions;
- enhance the efficiency of the existing scrubber at Culley Units 2 and 3 for additional removal of sulphur dioxide emissions;
- install a baghouse for further particulate matter reductions at Culley Unit 3 by June 30, 2007;
- conduct a Sulphuric Acid Reduction Demonstration Project as an environmental mitigation project designed to demonstrate an advance in pollution control technology for the reduction of sulfate emissions; and
- pay a $600,000 civil penalty.

The Company anticipates that the settlement would result in total capital expenditures through 2007 in a range between $16 million and $28 million. Other than the $600,000 civil penalty, which was accrued in the second quarter of 2003, the implementation of the settlement, including these capital expenditures and related operating expenses, are expected to be recovered through rates.

*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 with the most recent correspondence provided on March 26, 2001.

<u>Manufactured Gas Plants</u>

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 (VRP) 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 VRP. 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 been initiated by the Company to confirm that the sites continue to pose no such risk.

On October 6, 2003, SIGECO filed applications to enter four of the manufactured gas plant sites in IDEM's VRP. The remaining site is currently being addressed in the VRP by another Indiana utility. SIGECO is adding its four sites into the renewal of the global Voluntary Remediation Agreement that Indiana Gas has in place with IDEM for its manufactured gas plant sites. The total costs, net of other PRP involvement and insurance recoveries, that may be incurred in connection with further investigation, and if necessary, remedial work at the four SIGECO sites cannot be determined at this time.

**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 the IURC. The retail gas operations of the Ohio operations are subject to regulation by the PUCO.

All metered gas rates in Indiana contain a gas cost adjustment (GCA) clause, and all metered gas rates in Ohio contain a gas cost recovery (GCR) clause. GCA and GCR clauses allow the Company to charge for changes in the cost of purchased gas. Metered electric rates contain a fuel adjustment clause (FAC) 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. Rate structures in the Company's territories 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.

GCA, GCR, and FAC procedures involve periodic filings and IURC and PUCO hearings to establish the amount of price adjustments for a designated future period. The procedures also provide for inclusion in later periods of any variances between the estimated cost of gas, cost of fuel, and net energy cost of purchased power and actual costs incurred. 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 IURC has also applied the statute authorizing GCA and FAC procedures to reduce rates when necessary to limit net operating income to a level authorized in its last general rate order through the application of an earnings test. For the recent past, the earnings test has not affected the Company's ability to recover costs, and the Company does not anticipate the earnings test will restrict recovery in the near future.

<u>Ohio Uncollectible Accounts Expense Tracker</u>

On December 17, 2003, the PUCO approved a request by VEDO and several other regulated Ohio gas utilities to establish a mechanism to recover uncollectible account expense outside of base rates. The tariff mechanism establishes an automatic adjustment procedure to track and recover these costs instead of providing the recovery of the historic amount in base rates. Through this order, VEDO received authority to defer its 2003 uncollectible accounts expense to the extent it differs from the level included in base rates. The Company estimated the difference to approximate $4 million in excess of that included in base rates, and accordingly reversed previously established reserves and recorded a regulatory asset for the difference, totaling $3.0 million.

Gas Cost Recovery (GCR) Audit Proceedings

There is an Ohio requirement that Ohio gas utilities undergo a biannual audit of their gas acquisition practices in connection with the gas cost recovery (GCR) mechanism. In the case of VEDO, the two-year period began in November 2000, coincident with the Company's acquisition of the Ohio operations and commencement of service in Ohio. The audit provides the initial review of the portfolio administration arrangement between VEDO and ProLiance. The external auditor retained by the PUCO staff recently submitted an audit report wherein it recommended a disallowance of approximately $7 million of previously recovered gas costs. The Company believes a large portion of the third party auditor recommendations is without merit. There are two elements of the recommendations relating to the treatment of a pipeline refund and a penalty which VEDO does not oppose. A hearing has been held, and based on its audit report, the PUCO staff has recommended a $6.1 million disallowance. The Ohio Consumer Counselor has submitted testimony to support an $11.5 million disallowance. For this PUCO audit period, any disallowance relating to the Company's ProLiance arrangement will be shared by the Company's joint venture partner. Based on a review of the matters, the Company has reserved $1.1 million for its estimated share of a potential disallowance. The Company believes that these proceedings will not likely have a material effect on the Company's operating results or financial condition. However, the Company can provide no assurance as to the ultimate outcome of this proceeding.

Recovery of Purchased Power

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 2004, 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.

Regulatory Initiatives

In addition to the timely recovery of incremental NOx environmental expenditures discussed above, the Company is pursuing base rate cases in its three gas territories. The last general rate increase for VEDO and Indiana Gas was in 1992, and was in 1996 for SIGECO gas.

The Company is currently in a collaborative dialogue with the OUCC regarding SIGECO's existing gas rates. If an agreement is reached between the parties as a result of that process, it will be subject to review and approval by the IURC.

The Company expects to file a base rate case for Indiana Gas' territory during the first quarter of 2004 and for VEDO in the second quarter of 2004. Additionally, as part of the rate case process, the Company is pursuing authority for recovery of the costs to comply with the Pipeline Safety Act of 2002 and for regulatory authority to amortize periodic expense incurred to overhaul its electric turbines. The timing and ultimate outcome of any of these regulatory initiatives is uncertain.

**Competition**

The utility industry has undergone dramatic structural change for several years, resulting in increasing competitive pressures faced by electric and gas utility companies. 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**

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 MISO is committed to reliability, the nondiscriminatory operation of the bulk power transmission system, and to working with all stakeholders to create cost-effective and innovative solutions. The Carmel, Indiana, based MISO began operations in December 2001 and serves the electrical transmission needs of much of the Midwest. 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, and export power to the wholesale market 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.

## Results of Operations of the Nonregulated Group

The Nonregulated Group is comprised of four primary business areas: Energy Marketing and Services, Coal Mining, Utility Infrastructure Services, and Broadband. Energy Marketing and Services markets natural gas and provides energy management services, including energy performance contracting services. Coal Mining mines and sells coal and generates IRS Code Section 29 investment tax credits relating to the production of coal-based synthetic fuels. Utility Infrastructure Services provides underground construction and repair, facilities locating, and meter reading services. Broadband invests in broadband communication services such as analog and digital cable television, high-speed Internet and data services, and advanced local and long distance phone services. In addition, the Nonregulated Group has other businesses that provide utility services, municipal broadband consulting, and retail products and services, and that invest in energy-related opportunities, real estate, and leveraged leases. The Nonregulated Group supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, utility infrastructure services, and other services.

The results of operations of the Nonregulated Group before certain intersegment eliminations and reclassifications for the years ended December 31, 2003, 2002, and 2001, follow:

| *(In millions, except per share amounts)* | 2003 | 2002 | 2001 |
|---|---|---|---|
| **Energy services & other revenues** | **$ 219.2** | **$ 352.3** | **$ 741.8** |
| Operating Expenses: | | | |
| Cost of energy services & other | 180.7 | 311.5 | 699.1 |
| Operating expenses | 37.2 | 36.1 | 36.3 |
| Restructuring costs | - | - | 3.5 |
| Total operating expenses | 217.9 | 347.6 | 738.9 |
| **OPERATING INCOME** | **1.3** | **4.7** | **2.9** |
| Other income: | | | |
| Equity in earnings of unconsolidated affiliates | 12.7 | 10.9 | 13.9 |
| Other – net | 10.2 | 6.1 | 11.4 |
| Total other income | 22.9 | 17.0 | 25.3 |
| Interest expense | 9.7 | 9.1 | 12.5 |
| **INCOME BEFORE TAXES** | **14.5** | **12.6** | **15.7** |
| Income taxes | (13.2) | (6.9) | (4.7) |
| Minority interest | 0.1 | 0.5 | 0.6 |
| **INCOME BEFORE EXTRAORDINARY LOSS** | **27.6** | **19.0** | **19.8** |
| Extraordinary loss - net of tax | - | - | (7.7) |
| **NET INCOME** | **$ 27.6** | **$ 19.0** | **$ 12.1** |
| **BASIC EARNINGS PER SHARE** | **$ 0.39** | **$ 0.28** | **$ 0.18** |
| NET INCOME ATTRIBUTED TO: | | | |
| Energy Marketing & Services | $ 20.7 | $ 15.0 | $ 11.3 |
| Coal Mining | 13.8 | 12.2 | 13.6 |
| Utility Infrastructure | (0.8) | (1.2) | (0.6) |
| Broadband | (1.0) | 0.4 | (0.1) |
| Other Businesses | (5.1) | (7.4) | (12.1) |

Nonregulated earnings for the year ended December 31, 2003, increased $8.6 million. Energy Marketing and Services' recurring operations contributed $18.1 million in earnings, or $3.1 million of the increase over 2002. A majority of the Energy Marketing and Services' earnings were generated by gas marketing operations, and a majority of the increase, or $2.3 million, was contributed by performance contracting operations. Coal Mining increased $1.6 million due to increased synfuel-related earnings, offset by lower mining results. In addition, net gains totaling $2.7 million after tax were recognized in 2003 from business and investment divestitures.

For the year ended December 31, 2002, earnings from the Nonregulated Group increased $6.9 million when compared to 2001. The increase is primarily due to increased earnings from gas marketing operations which are part of the Energy Marketing and Services and a smaller loss incurred by the Company's broadband consulting operations which are part of Other Businesses. The year ended December 31, 2001, included $2.2 million after tax, or $0.04 per share, in nonrecurring restructuring costs and $7.7 million after tax, or $0.12 per share, related to an extraordinary loss from the divestiture of leveraged leases. In addition, 2001 benefited from gains recognized upon sale of investments by an unconsolidated affiliate, and 2002 was negatively affected by a change in Indiana corporate income tax laws enacted in June 2002, which required the recalculation of deferred tax obligations and earnings from leveraged lease investments at the date of enactment of the law.

**Energy Marketing & Services**

Energy Marketing and Services is comprised of the Company's gas marketing and performance contracting operations and held the Company's investment in Genscape, Inc. (Genscape), a company that provides real-time power plant and transmission line status information using wireless technology. The investment in Genscape was sold in the third quarter of 2003 resulting in an after tax gain of $2.6 million.

Gas marketing operations are performed through the Company's investment in ProLiance Energy LLC (ProLiance), a nonregulated energy marketing affiliate of Vectren and Citizens Gas and Coke Utility (Citizens Gas). ProLiance provides natural gas and related services to Indiana Gas, the Ohio operations, and Citizens Gas and also began providing services to SIGECO and Vectren Retail, LLC (the Company's retail gas marketer) in 2002. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. ProLiance's primary customers are utilities and other large end use customers.

In June 2002, the integration of Vectren's wholly owned gas marketing subsidiary, SIGCORP Energy Services, LLC (SES), with ProLiance was completed. SES provided natural gas and related services to SIGECO and others prior to the integration. In exchange for the contribution of SES' net assets totaling $19.2 million, Vectren's allocable share of ProLiance's profits and losses increased from 52.5% to 61%, consistent with Vectren's new ownership percentage. The transfer of net assets was accounted for at book value, consistent with joint venture accounting, and did not result in any gain or loss. In March 2001, Vectren's allocable share of profits and losses increased from 50% to 52.5% when ProLiance began managing the Ohio operations' gas portfolio. Governance and voting rights remain at 50% for each member; and therefore, Vectren continues to account for its investment in ProLiance using the equity method of accounting.

Energy Systems Group, LLC (ESG) provides energy performance contracting and facility upgrades through its design and installation of energy-efficient equipment. Prior to April 2003, ESG was a consolidated venture between the Company and Citizens Gas with the Company owning two-thirds. In April 2003, the Company purchased the remaining interest in ESG for approximately $4 million.

Net income generated by Energy Marketing and Services for the year ended December 31, 2003, was $20.7 million, as compared to $15.0 million in 2002 and $11.3 million in 2001. Gas marketing operations, performed through ProLiance, contributed $15.3 million in earnings in 2003, as compared to $14.6 million in 2002, and $10.5 million in 2001. The $0.7 million increase over 2002 was principally attributable to increased storage capacity coupled with more volatile gas prices, offset by settlement disputes related to the contingency discussed below. The $4.1 million increase in 2002 compared to 2001 is primarily due to increased operations at ProLiance and increased ownership. The performance contracting operations, performed through ESG, contributed earnings $3.0 million in 2003, $0.7 million in 2002, and $0.9 million in 2001. The $2.3 million increase in 2003 compared to 2002 is due primarily to success in obtaining higher margins and working from a higher construction backlog at the end of 2002 as well as increased ownership as of April 2003.

<u>ProLiance Contingency</u>

There is currently a lawsuit pending in the United States District Court for the Northern District of Alabama filed by the City of Huntsville, Alabama d/b/a Huntsville Utilities, Inc. (Huntsville Utilities) against ProLiance. Huntsville Utilities asserts claims based on negligent provision of portfolio services and/or pricing advice, fraud, fraudulent inducement, and other theories. These claims relate generally to several basic arguments: (1) negligence in providing advice and/or administering portfolio arrangements; (2) alleged promises to provide gas at a below-market rate; (3) the creation and repayment of a "winter levelizing program" instituted by ProLiance in conjunction with the Manager of Huntsville's Gas Utility, to allow Huntsville Utilities to pay its gas bills from the winter of 2000-2001 over an extended period of time coupled with the alleged ignorance about the program on the part of Huntsville Utilities' Gas Board, and; (4) the sale of Huntsville Utilities' gas storage supplies to repay the balance owed on the winter levelizing program and the authority of Huntsville Utilities' gas manager to approve those sales. In a press conference on May 21, 2002, Huntsville Utilities asserted its monetary damages to be approximately $10 million, and seeks to treble that amount. ProLiance has made counterclaims asserting breach of contract, among others, based on Huntsville Utilities' refusal to take gas under fixed price agreements. Both parties have denied the charges contained in the respective claims.

In 2003, ProLiance established reserves for amounts due from Huntsville Utilities due to uncertainties surrounding collection. ProLiance denies any wrongdoing, believes its actions were proper under the contract and amendments signed by the manager of Huntsville's Gas Utility, and is vigorously defending against the suit. ProLiance is an insured under a policy of insurance providing defense costs which may provide in whole or in part, indemnification within the policy limits for claims asserted against ProLiance. Accordingly, no other loss contingencies have been recorded at this time. However, it is not possible to predict or determine the outcome of this litigation and accordingly there can be no assurance that ProLiance will prevail. It is not currently expected that costs associated with this matter will have a material adverse effect on Vectren's consolidated financial position or liquidity but an unfavorable outcome could possibly be material to Vectren's earnings.

**Coal Mining**

The Coal Mining Group mines and sells coal to the Company's utility operations and to other third parties through its wholly owned subsidiary Vectren Fuels, Inc. (Fuels). The Coal Mining Group also generates IRS Code Section 29 investment tax credits relating to the production of coal-based synthetic fuels through its 8.3% ownership interest in Pace Carbon Synfuels, LP (Pace Carbon). Pace Carbon developed, owns, and operates four projects to produce and sell coal-based synthetic fuel (synfuel) utilizing Covol technology. Vectren accounts for is investment in Pace Carbon using the equity method. In addition, Fuels receives synfuel-related fees from synfuel producers unrelated to Pace Carbon for a portion of its coal production.

Coal Mining net income for the year ended December 31, 2003, was $13.8 million, as compared to $12.2 million in 2002, and $13.6 million in 2001. Synfuel-related results, which include earnings from Pace Carbon and synfuel processing fees earned by Fuels, contributed all of the earnings in 2003, $9.0 million in 2002, and $6.6 million in 2001. Increasing production of synthetic fuel by Pace Carbon in 2003 and 2002 has generated a greater amount of Section 29 tax credits that have been utilized by the Company, reducing income tax expense in those years. The increase in synfuel-related earnings has been offset by mining operations that have experienced decreased yields due to poor mining conditions and increased mine development cost amortization.

IRS Section 29 Investment Tax Credit Recent Developments

Under Section 29 of the Internal Revenue Code, manufacturers such as Pace Carbon, receive a tax credit for every ton of synthetic fuel sold. To qualify for the credits, the synthetic fuel must meet three primary conditions: 1) there must be a significant chemical change in the coal feedstock, 2) the product must be sold to an unrelated person, and 3) the production facility must have been placed in service before July 1, 1998.

In past rulings, the Internal Revenue Service (IRS) has concluded that the synthetic fuel produced at the Pace Carbon facilities should qualify for Section 29 tax credits. The IRS issued a private letter ruling with respect to the four projects on November 11, 1997, and subsequently issued an updated private letter ruling on September 23, 2002.

As a partner in Pace Carbon, Vectren has reflected total tax credits under Section 29 in its consolidated results through December 31, 2003, of approximately $39 million. Vectren has been in a position to fully utilize the credits generated and continues to project full utilization.

In June 2003, the IRS, in an industry-wide announcement, stated that it would review the scientific validity of test procedures and results presented as evidence of significant chemical change. During this review, the IRS suspended the issuance of new private letter rulings on that subject. In October 2003, the IRS completed its review and determined that the test procedures and results used by taxpayers are scientifically valid if the procedures are applied in a consistent and unbiased manner. Also, the IRS will issue new private letter rulings based on revised standards; however, it has continuing concerns regarding the sampling and data/record retention practices prevalent in the synthetic fuels industry.

During June 2001, the IRS began a tax audit of Pace Carbon for the 1998 tax year and later expanded the audit to include tax years 1999, 2000, and 2001. Based on conclusions reached in the industry-wide review and recently issued private letter rulings involving other synthetic fuel facilities, Vectren believes chemical change issues from these audits may soon be resolved. However, the IRS has not directly notified Pace Carbon of any resolution.

Vectren believes it is justified in its reliance on the private letter rulings for the Pace Carbon facilities, that the test results that Pace Carbon presented to the IRS in connection with its private letter rulings are scientifically valid, and that Pace Carbon has operated its facilities in compliance with its private letter rulings and Section 29 of the Internal Revenue Code. However, at this time, Vectren cannot provide any assurance as to the outcome of these audits concerning the issue of chemical change or any other issue raised during the audits relative to its investment in Pace Carbon. Further, it is expected that Section 29 investments will continue to draw attention from various interest groups.

**Utility Infrastructure Services**

Utility Infrastructure Services provides underground construction and repair to gas, water, electric and telecommunications companies primarily through its investment in Reliant Services, LLC (Reliant) and Reliant's 100% ownership in Miller Pipeline. Reliant is a 50% owned strategic alliance with an affiliate of Cinergy Corp. and is accounted for using the equity method of accounting. Results in recent years have been affected by cutbacks of underground construction and repair projects by gas distribution customers. In the second half of 2003, Miller returned to profitability due to an increase in construction and repair projects as utilities began to return to historical expenditure levels.

**Broadband**

Broadband invests in communication services, such as cable television, high-speed Internet, and advanced local and long distance phone services. The Company has an approximate 2% equity interest and a convertible subordinated debt investment in Utilicom Networks, LLC (Utilicom) that if converted bring the Company's ownership interest up to 16%. Utilicom is a provider of bundled communication services focusing on last mile delivery to residential and commercial customers. The Company also has an approximate 19% equity interest in SIGECOM Holdings, Inc. (Holdings), which was formed by Utilicom to hold interests in SIGECOM, LLC (SIGECOM). SIGECOM provides broadband services to over 29,000 customers, averaging nearly 3 revenue generating units per customer, in the greater Evansville, Indiana area and continues to increase its positive operating cash flow.

The equity investments in Utilicom and Holdings are accounted for using the cost method of accounting. As a result, for years ended December 31, 2003, 2002, and 2001, these investments had no significant impact on the Company's operating results.

Utilicom also plans to provide broadband services to the greater Indianapolis, Indiana and Dayton, Ohio markets. However, the funding of these projects has been delayed due to the continued difficult environment within the telecommunication capital markets, which has prevented Utilicom from obtaining debt financing on terms it considers acceptable. While the existing investors remain interested in the Indianapolis and Dayton projects, the Company is not required to make further investments and does not intend to proceed unless commitments are obtained to fully fund these projects. Franchising agreements have been extended in both locations.

For the year ended December 31, 2003, Broadband losses were $1.0 million. This reflects the impact of a $1.2 million after tax loss on the sale of the Company's investment in First Mile, a small broadband operation in Indianapolis, Indiana.

**Other Businesses**

The Other Businesses Group includes a variety of wholly owned operations and investments. For the year ended December 31, 2003, the Other Businesses Group losses, including operating expenses, were $5.1 million, as compared to losses of $7.4 million in 2002, and losses of $12.1 million in 2001. The $2.3 million improvement occurring in 2003 resulted from a $1.2 million after tax gain recognized upon sale of IEIFS, LLC (IEIFS), a debt collection subsidiary; and the operating results of Vectren Retail, LLC (Vectren Source). Vectren Source began operations in 2001 and provides natural gas and other related products and services primarily in Ohio, serving over 72,000 customers opting for choice among energy providers. Source's losses for the year ended December 31, 2003, were $1.9 million, as compared to $2.6 million in 2002.

The net loss incurred in 2002 compared to 2001 narrowed $4.7 million. The improvement results from a $7.7 million extraordinary loss incurred in 2001 related to the divesture of leveraged leases that generated positive cash flow of approximately $67 million. In addition, the Company's wholly owned broadband consulting company incurred charges in 2002 and 2001 related to the settlement of construction contracts and the reorganization of its operations, allowing it to focus on consulting services. The net losses incurred in those years totaled $2.8 million in 2002, as compared $8.0 million in 2001. These factors have been partially offset by less leveraged lease and other interest income in 2002 due to divestures, a change in Indiana tax law in 2002, and gains recognized in 2001 from the Haddington Energy Partnerships' (Haddington) sale of investments.

The Haddington partnerships are equity method investments that invest in energy-related ventures. During 2001, these partnerships sold investments resulting in gains reflected by the Company totaling $6.2 million ($3.8 million after tax). The most significant portion of these earnings was derived from Haddington's sale of Bear Paw Investments, LLC (Bear Paw). In March 2001, Haddington sold its investment in Bear Paw in exchange for a combination of cash and securities. The cost of Haddington's Bear Paw investment approximated $5.1 million, and the net proceeds received totaled $18.1 million, resulting in a gain of $13.0 million. The Company recognized its portion of the pre-tax gain totaling $3.9 million in March 2001. Later in 2001, as the securities received were sold, the Company recognized its portion of the additional earnings totaling $1.0 million.

**Significant Fluctuations**

Revenues and Cost of Revenues

Resulting from the integration of the Company's two gas marketers, revenues and cost of revenues decreased significantly. Prior to June 1, 2002, the operations of SES were consolidated. Subsequent to June 1, 2002, SES' operating results, now part of ProLiance, are reflected in equity in earnings of unconsolidated affiliates. SES' operations were the majority of nonregulated revenues and cost of revenues. As a result of the integration, revenues decreased $183.7 million in 2003 and $392.5 million in 2002. Cost of revenues decreased $176.1 million in 2003 and $387.1 million in 2002. The decreases have been partially offset by increased results at ESG, Fuels, and Vectren Source. Vectren Source's revenues were $44.3 million in 2003, $10.3 million in 2002, and $0.3 million in 2001.

Equity in Earnings of Unconsolidated Affiliates

The primary components of equity in earnings of unconsolidated affiliates relate to earnings of ProLiance and losses incurred by Pace Carbon. For the years ended December 31, 2003, 2002, and 2001, the Company's portion of ProLiance's earnings were $25.9 million, $19.1 million, and $12.8 million, respectively. For the years ended December 31, 2003, 2002, and 2001, the Company's portion of Pace Carbon losses were $11.4 million, $6.8 million, and $4.5 million, respectively. In addition 2001, includes $6.2 million in earnings from the Haddington partnerships, as discussed above.

Other - net

During 2003, Other - net increased $4.1 million. The increase is due to the gain recognized from the sale of Genscape, which on a pre-tax basis approximated just over $5 million. The decrease in 2002 compared to 2001 totaling $5.3 million is primarily due to less leverage lease and interest income, which is an effect of the divestures of structured finance arrangements in 2001 and 2002.

## Critical Accounting Policies

Management is required to make judgments, assumptions, and estimates that affect the amounts reported in the consolidated financial statements and the related disclosures that conform to accounting principles generally accepted in the United States. 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 judgment. These include the estimates to perform goodwill and other asset impairments tests and to determine pension and postretirement benefit obligations. The Company makes other estimates in the course of accounting for unbilled revenue and the effects of regulation that are critical to the Company's financial results but that are less likely to be impacted by near term changes. Other estimates that significantly affect the Company's results, but are not necessarily critical to operations, include depreciation of utility and non-utility plant, the valuation of derivative contracts, and the allowance for doubtful accounts, among others. Actual results could differ from these estimates.

### Impairment Review of Investments

The Company has investments in notes receivable, entities accounted for using the cost method of accounting, and entities accounted for using the equity method of accounting. 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, or for notes that are collateral dependent, a comparison of the collateral's fair value to the carrying amount of the note. An impairment analysis of cost method and equity method investments involves comparison of the investment's estimated fair value to its carrying amount. Fair value is estimated using market comparisons, appraisals, and/or discounted cash flow analyses. Calculating free cash flows and fair value using the above methods is subjective and requires significant judgment in growth assumptions, longevity of cash flows, and discount rates (for fair value calculations).

During 2002, the Company performed an impairment analysis on its Utilicom-related investments. The Company used market comparisons to estimate fair value for the cost method portion of the Utilicom investment and a free cash flow analysis to estimate fair value for the note receivable portion of the Utilicom investment. No impairment charge was recorded as a result of these tests. However, a 10% decrease in the fair value that was estimated using market comparables would have resulted in an impairment charge to the cost method investment that would not have been material. A 10% decrease in the cash flow growth assumption utilized to calculate Utilicom's free cash flows would have resulted in no impairment charge to the notes receivable. During 2003, no impairment analysis was performed as no triggering events occurred during the year.

Impairment tests on other investments were also conducted using appraisals and discounted cash flow models to estimate fair value. No impairment charges resulted from these analyses in 2002 and a $3.9 million write-off of the BABB investments resulted in 2003. For the other impairment tests performed during 2002, a 10% adverse change in the calculated or appraised fair value of collateral or a 100 basis point adverse change in the discount rate used to estimate fair value would have resulted in an approximate $3 million impairment charge. A 10% adverse change of such factors would not have affected the 2003 BABB write-off.

### 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 17 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 in both 2003 and 2002 and therefore resulted in no impairment.

Estimating fair value using a discounted cash flow model is subjective and requires significant judgment in applying a discount rate, growth assumptions, company expense allocations, and longevity of cash flows. A 100 basis point increase in the discount rate utilized to calculate the Gas Utility Services segment's fair value also would have resulted in no impairment charge in 2003 or 2002.

**Pension and Other Postretirement Obligations**

The Company 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 the Company's pension and postretirement plans. The Company annually measures its obligations on September 30. The Company used the following weighted average assumptions to develop 2003 periodic benefit cost: a discount rate of 6.75%, an expected return on plan assets before expenses of 9.0%, a rate of compensation increase of 4.25%, and a health care cost trend rate of 10% in 2003 declining to 5% in 2006. During 2003, the Company reduced the discount rate and rate of compensation increase by 75 basis points to value 2003 ending pension and postretirement obligations due to a decline in benchmark interest rates. The Company also lengthened to 2009 the time in which the health care trend rate declines to 5% primarily due to increases in healthcare costs. In addition, the Company reduced its 2004 expected return on plan assets 50 basis points from that used to estimate 2003 expense due to recent lower investment returns and lower interest rates. Future changes in health care costs, work force demographics, interest rates, or plan changes could significantly affect the estimated cost of these future benefits.

For the year ended December 31, 2003, a one percentage point adverse change in the assumed health care cost trend rate for the postretirement health care plans would have decreased pre-tax income by approximately $0.7 million and would have increased the postretirement liability by approximately $8.4 million. Management estimates that a 50 basis point reduction in the expected return on plan assets would have increased 2003 periodic benefit cost by approximately $1 million and a 50 basis point decrease in the discount rate would have also increased periodic benefit cost by approximately $1 million.

**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, the method these estimates are derived from is 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 judgment and is critical in assessing the recoverability of regulatory assets as well as the ability to continue to account for its activities based on the criteria set forth in 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.

## Impact of Recently Issued Accounting Guidance

**SFAS 132 (Revised 2003)**

In December 2003, FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS 132), to improve financial statement disclosures for defined benefit plans. The change replaces existing FASB disclosure requirements for pensions and postretirement plans. The guidance is effective for fiscal years ending after December 15, 2003. The adoption did not impact the Company's results of operations or financial condition. The incremental disclosure requirements are included in these financial statements in Note 6. In addition to expanded annual disclosures, SFAS 132, as revised, requires the reporting of various elements of pension and other postretirement benefit costs on a quarterly basis.

**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. The Company adopted this statement on January 1, 2003. The adoption was not material to the Company's results of operations or financial condition.

The Company collects an estimated cost of removal of its utility plant through depreciation rates established by regulatory proceedings. As of December 31, 2003, and 2002, such removal costs approximated $229 million and $210 million, respectively. In 2002, the cost of removal has been included in *Other removal costs*, which is in noncurrent liabilities. In 2003, the Company re-characterized other removal costs to *Regulatory liabilities* upon adoption of SFAS 143.

**SFAS 149**

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends and clarifies the accounting guidance on (1) derivative instruments (including certain derivative instruments embedded in other contracts) and (2) hedging activities that fall within the scope of FASB Statement No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities." SFAS 149 amends SFAS 133 to reflect decisions that were made (1) as part of the process undertaken by the Derivatives Implementation Group (DIG), which necessitated amending SFAS 133, (2) in connection with other projects dealing with financial instruments, and (3) regarding implementation issues related to the application of the definition of a derivative. SFAS 149 also amends certain other existing pronouncements which will result in more consistent reporting of contracts that are derivatives in their entirety or that contain embedded derivatives that warrant separate accounting. SFAS 149 is effective (1) for contracts entered into or modified after June 30, 2003, with certain exceptions and (2) for hedging relationships designated after June 30. The guidance is to be applied prospectively. The adoption did not have a material effect on the Company's results of operations or financial condition.

**SFAS 150**

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (SFAS 150). SFAS 150 requires issuers to classify as liabilities the following three types of freestanding financial instruments: mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets, and certain obligations to issue a variable number of shares. SFAS 150 was effective immediately for financial instruments entered into or modified after May 31, 2003; otherwise, the standard was effective for all other financial instruments at the beginning of the Company's third quarter of 2003. In October 2003, the FASB issued further guidance regarding mandatorily redeemable stock which is effective January 1, 2004, for the Company. The Company has approximately $200,000 of outstanding preferred stock of a subsidiary that is redeemable on terms outside the Company's control. However, the preferred stock is not redeemable on a specified or determinable date or upon an event that is certain to occur. The adoption of SFAS 150 on January 1, 2004, did not affect the Company's results of operations or financial condition.

**FASB Interpretation (FIN) 45**

In November 2002, the FASB issued 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 fair value of the obligations it has undertaken. The initial recognition and measurement provisions were applicable on a prospective basis to guarantees issued or modified after December 31, 2002. Since that date, the adoption has not had a material effect on the Company's results of operations or financial condition. The incremental disclosure requirements are included in these financial statements in Note 12.

**FIN 46/46-R (Revised in December 2003)**

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 (VIE) and significantly changes the consolidation requirements for those entities. FIN 46 is intended to achieve more consistent application of consolidation policies related to VIE's and thus improves comparability between enterprises engaged in similar activities when those activities are conducted through VIE's. In December 2003, the FASB completed its deliberations of proposed modifications to FIN 46 and decided to codify both the proposed modifications and other decisions previously issued through certain FASB Staff Positions into one document that was issued as a revision to the original Interpretation (FIN 46-R). FIN 46-R currently applies to VIE's created after January 31, 2003, and to VIE's in which an enterprise obtains an interest after that date. For entities created prior to January 31, 2003, FIN 46 is to be adopted no later than the end of the first interim or annual reporting period ending after March 15, 2004.

The Company has neither created nor obtained an interest in a VIE since January 31, 2003. Certain other entities that the Company was involved with prior to that date, including limited partnership investments that operate affordable housing projects, are still being evaluated to determine if the entity is a VIE and, if so, if Vectren is the primary beneficiary. If these entities are determined to be VIE's and Vectren is determined to be the primary beneficiary, the effect to the Company's financial statements would not be material.

**Staff Accounting Bulletin No. 104**

In December 2003, the SEC published Staff Accounting Bulletin (SAB) No. 104, "Revenue Recognition". This SAB updates portions of the SEC staff's interpretive guidance provided in SAB 101 and included in Topic 13 of the Codification of Staff Accounting Bulletins. SAB 104 deletes interpretative material no longer necessary and conforms the interpretive material retained because of pronouncements issued by the FASB's EITF on various revenue recognition topics, including EITF 00-21, "Revenue Arrangements with Multiple Deliverables." The Company's adoption of the standard did not have an impact on its revenue recognition policies.

**<u>United States Securities and Exchange Commission (SEC) Informal Inquiry</u>**

As more fully described in the 2002 consolidated financial statements, the Company restated its annual consolidated financial statements for 2000 and 2001, and its 2002 quarterly results. The Company received an informal inquiry from the SEC with respect to this restatement. In response, the Company met with the SEC staff and provided information in response to their requests, with the most recent response provided on July 26, 2003.

## Financial Condition

Within Vectren's consolidated group, VUHI funds Vshort-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corp (Vectren Capital) funds short-term and long-term financing needs of the Nonregulated Group and corporate operations. Vectren Corporation guarantees Vectren Capital's debt, but does not guarantee VUHI's debt. Vectren Capital's long-term and short-term obligations outstanding at December 31, 2003, totaled $113.0 million and $87.6 million, respectively. VUHI's outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. VUHI's long-term and short-term obligations outstanding at December 31, 2003, totaled $550.0 million and $184.4 million, respectively. Additionally, prior to VUHI's formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations.

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

VUHI's and Indiana Gas' credit ratings on outstanding senior unsecured debt at December 31, 2003, are A-/Baa1 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. SIGECO's credit ratings on outstanding senior unsecured debt are BBB+/Baa1. SIGECO's credit ratings on outstanding secured debt are A-/A3. VUHI's commercial paper has a credit rating of A-2/P-2. Vectren Capital's senior unsecured debt is rated BBB+/Baa2. Moody's current outlook is stable while Standard and Poor's current outlook is negative. The ratings of Moody's and Standard and Poor's are categorized as investment grade and are unchanged from December 31, 2002. In July 2003, Standard and Poor's reaffirmed its ratings, and Moody's reaffirmed its ratings on VUHI's senior unsecured debt. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-55% 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 49% and 46% of total capitalization, including current maturities of long-term debt and long-term debt subject to tender, at December 31, 2003, and 2002, respectively.

The Company expects the majority of its capital expenditures, investments, and debt security redemptions to be provided by internally generated funds. However, due to significant capital expenditures for NOx compliance equipment at SIGECO and to further strengthen the Company's capital structure and the capital structures of VUHI and its utility subsidiaries, the Company has completed certain financing transactions as more fully described in the discussion of financing activity below.

### Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary historical source of liquidity to fund working capital requirements has been cash generated from operations. Cash flow from operating activities decreased during the year ended December 31, 2003, compared to 2002 by $115.2 million and increased $104.2 million in 2002 compared to 2001. The primary reason for these changes was favorable changes in working capital accounts occurring in 2002 due to lower gas prices in that year and higher gas prices in 2003 and 2001. In 2003, the decrease was partially offset by 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. Additionally, short-term borrowings are required for capital projects and investments until they are permanently financed.

Cash flow provided by financing activities of $45.8 million for the year ended December 31, 2003, includes the effects of the permanent financing executed during the current year in which approximately $366 million in equity, debt, and hedging net proceeds were received and used to retire higher coupon long-term debt and other short term borrowings. Common stock dividends have increased in 2003 compared to 2002 due to the issuance of new securities and board authorized increases in the dividend rate.

Cash flow required for financing activities of $57.6 million for the year ended December 31, 2002, includes increased common stock dividends compared to 2001. Borrowings also increased due to financing a portion of capital expenditures for NOx compliance temporarily with short-term borrowings. Cash flow required for financing activities of $2.7 million for the year ended December 31, 2001, includes $59.5 million of reductions in borrowings and preferred stock and $69.5 million in common stock dividends, offset by the issuance of $129.4 million of common stock. During 2001, $473.4 million of net proceeds from equity and debt issuances were utilized to pay down short-term borrowings.

*Equity Issuance*
In March 2003, the Company filed a registration statement with the Securities and Exchange Commission with respect to a public offering of authorized but previously unissued shares of common stock as well as the senior unsecured notes of VUHI described below. In August 2003, the registration became effective, and an agreement was reached to sell approximately 7.4 million shares to a group of underwriters. The net proceeds totaled $163.2 million and were utilized entirely by VUHI and VUHI's subsidiaries to repay short-term borrowings and to retire long-term debt with higher interest rates.

*VUHI Debt Issuance*
In July 2003, VUHI issued senior unsecured notes with an aggregate principal amount of $200 million in two $100 million tranches. The first tranche was 10-year notes due August 2013, with an interest rate of 5.25% priced at 99.746% to yield 5.28% to maturity (2013 Notes). The second tranche was 15-year notes due August 2018 with an interest rate of 5.75% priced at 99.177% to yield 5.80% to maturity (2018 Notes).

The notes are guaranteed by the VUHI's three public utilities: SIGECO, Indiana Gas, and VEDO. These guarantees are full and unconditional and joint and several. In addition, they have no sinking fund requirements, and interest payments are due semi-annually. The notes may be called by VUHI, 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 20 basis points for the 2013 Notes and 25 basis points for the 2018 Notes.

Shortly before these issues, VUHI entered into several treasury locks with a total notional amount of $150.0 million. Upon issuance of the debt, the treasury locks were settled resulting in the receipt of $5.7 million in cash, which was recorded as a regulatory liability pursuant to existing regulatory orders. The value received is being amortized as a reduction of interest expense over the life of the issues.

The net proceeds from the sale of the senior notes and settlement of related hedging arrangements approximated $203 million and were used to repay short-term borrowing and to retire long-term debt with higher interest rates.

*SIGECO and Indiana Gas Debt Call*
During 2003, the Company called two first mortgage bonds outstanding at SIGECO and two senior unsecured notes outstanding at Indiana Gas. The first SIGECO bond had a principal amount of $45.0 million, an interest rate of 7.60%, was originally due in 2023, and was redeemed at 103.745% of its stated principal amount. The second

SIGECO bond had a principal amount of $20.0 million, an interest rate of 7.625%, was originally due in 2025, and was redeemed at 103.763% of the stated principal amount.

The first Indiana Gas note had a remaining principal amount of $21.3 million, an interest rate of 9.375%, was originally due in 2021, and was redeemed at 105.525% of the stated principal amount. The second Indiana Gas note had a principal amount of $13.5 million, an interest rate of 6.75%, was originally due in 2028, and was redeemed at the principal amount.

Pursuant to regulatory authority, the premiums paid to retire these notes totaling $3.6 million were deferred as a regulatory asset.

*Permanent Financing for the Ohio Operations Purchase*
In January 2001, the Company filed a registration statement with the Securities and Exchange Commission with respect to a public offering of authorized but previously unissued shares of common stock. In February 2001, the registration became effective, and an agreement was reached to sell approximately 6.3 million shares to a group of underwriters. The net proceeds totaled $129.4 million.

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.

Both issues are guaranteed by VUHI's three operating utility companies: SIGECO, Indiana Gas, and VEDO. These guarantees are full and unconditional and joint and several. In addition, 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 hedging arrangements totaled $344.0 million.

The proceeds received from the equity and debt issuance were used to refinance interim borrowing arrangements used to purchase the Ohio operations.

*Other Financing Transactions*
Other Company debt totaling $18.5 million in 2003, $6.5 million in 2001, and $7.6 million in 2001 was retired as scheduled.

At December 31, 2002, the Company had $26.6 million of adjustable rate senior unsecured bonds which could, at the election of the bondholder, be tendered to the Company when interest rates are reset. Such bonds were classified as *Long-term debt subject to tender*. During 2003, the Company re-marketed $4.6 million of the bonds through 2020 at a 4.5% fixed interest rate and remarketed $22.0 million of the bonds through 2030 at a 5.0% fixed interest rate. The bonds are now classified in *Long-term debt*.

Additionally, during 2003, the Company re-marketed $22.5 million of first mortgage bonds subject to interest rate exposure on a long term basis. The $22.5 million of mortgage bonds were remarketed through 2024 at a 4.65% fixed interest rate.

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.

Investing Cash Flow

Cash required for investing activities of $232.7 million for the year ended December 31, 2003, includes $236.2 million of requirements for capital expenditures. Investing activities for 2002 were $234.6 million. The decrease occurring in 2003 principally results from collections of notes receivable and distributions by unconsolidated affiliates offset by slightly higher capital expenditures.

Cash required for investing activities of $234.6 million for the year ended December 31, 2002, includes $218.7 million of requirements for capital expenditures. Investing activities for 2001 were $175.6 million. The $59.0 million increase occurring in 2002 is principally the result of the sale of leveraged lease and notes receivable investments in 2001.

**Available Sources of Liquidity**

At December 31, 2003, the Company has $531 million of short-term borrowing capacity, including $351 million for the Utility Group and $180 million for the wholly owned Nonregulated Group and corporate operations, of which approximately $166 million is available for the Utility Group operations and approximately $91 million is available for the wholly owned Nonregulated Group and corporate operations. The availability of short-term borrowing is reduced by outstanding letters of credit totaling $1.0 million, collateralizing Nonregulated Group activities.

Beginning in 2003, the Company began issuing new shares to satisfy dividend reinvestment plan requirements. During 2003, new equity issues from stock plans provided liquidity of approximately of $7.1 million. Management estimates such new share issues will add similar liquidity in succeeding years.

**Potential & Future Uses of Liquidity**

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2003:

| *(In millions)* | 2004 | 2005 | 2006 | 2007 | 2008 | Thereafter |
|---|---|---|---|---|---|---|
| Long-term debt [(1)] | $ 15.0 | $ 38.0 | $ - | $ 24.0 | $ - | $ 1,029.5 |
| Short-term debt | 274.9 | - | - | - | - | - |
| Commodity firm purchase commitments | 169.8 | 34.5 | - | - | - | - |
| Utility & nonutility plant purchase commitments [(2)] | 96.8 | 19.7 | 1.3 | - | - | - |
| Operating leases | 6.7 | 5.4 | 4.2 | 3.3 | 1.4 | 0.6 |
| Unconsolidated affiliate investments [(2)] [(3)] | 5.5 | 3.5 | - | - | - | - |
| Total | $568.7 | $101.1 | $ 5.5 | $ 27.3 | $ 1.4 | $ 1,030.1 |

(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 2003 (in millions) is $13.5 in 2004, $10.0 in 2005, $53.7 in 2006, $20.0 in 2007, zero in 2008, and $120.0 thereafter.

(2) The settlement period of these obligations is estimated.

(3) Future investments in Pace Carbon will be made to the extent Pace Carbon generates federal tax credits, with any such additional investments to be funded by these credits.

Planned Capital Expenditures & Investments

The timing and amount of capital expenditures and investments in nonregulated unconsolidated affiliates, including contractual purchase and investment commitments discussed above, for the five-year period 2004 - 2008 are estimated as follows:

| *(In millions)* | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|
| Capital expenditures | | | | | |
| Utility Group [1] | $ 252.9 | $ 213.8 | $ 222.9 | $ 216.4 | $ 233.6 |
| Nonregulated Group | 9.2 | 9.7 | 11.7 | 6.8 | 6.1 |
| Total capital expenditures | $ 262.1 | $ 223.5 | $ 234.6 | $ 223.2 | $ 239.7 |
| Investments in unconsolidated affiliates | $ 20.4 | $ 24.0 | $ 18.7 | $ 37.9 | $ 12.1 |

[1] Includes expenditures for NOx compliance of approximately $77.4 million in 2004, $19.7 million in 2005, and $3.6 million in 2006.

Off Balance Sheet Arrangements

*Ratings Triggers*
At December 31, 2003, $113.0 million of Vectren Capital's senior unsecured notes were subject to cross-default and ratings trigger provisions that would provide that the full balance outstanding is subject to prepayment if the ratings of Indiana Gas or SIGECO declined to BBB/Baa2. In addition, accrued interest and a make whole amount based on the discounted value of the remaining payments due on the notes would also become payable. The credit rating of Indiana Gas' senior unsecured debt and SIGECO's secured debt remains one level and two levels, respectively, above the ratings trigger.

*Guarantees and Letters of Credit*
In the normal course of business, Vectren Corporation issues guarantees to third parties on behalf of its consolidated subsidiaries and unconsolidated affiliates. Such guarantees allow those subsidiaries and affiliates to execute transactions on more favorable terms than the subsidiary or affiliate could obtain without such a guarantee. Guarantees may include posted letters of credit, leasing guarantees, and performance guarantees. As of December 31, 2003, guarantees issued and outstanding on behalf of unconsolidated affiliates approximated $6 million. In addition, prior to the effective date of FIN 45, the Company issued a guarantee approximating $4 million related to the residual value of an operating lease that expires in 2006. Through December 31, 2003, the Company has not been called upon to satisfy any obligations pursuant to its guarantees.

Pension and Postretirement Funding Obligations

The Company has not made significant contributions to its qualified pension plans in recent years. Due to recent market performance, it is likely to be necessary for the Company to make contributions to benefits plans in the coming years. Management currently estimates that the qualified pension plans will require Company contributions of approximately $5 million in 2004 and approximately $10 million in 2005.

## 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.
- The performance of projects undertaken by the Company's nonregulated businesses and the success of efforts to invest in and develop new opportunities, including but not limited to, the realization of Section 29 income tax credits and the Company's coal mining, gas marketing, and broadband strategies.

  Direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit rating, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, 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.

The Company also executes derivative contracts in the normal course of operations while buying and selling commodities to be used in operations and optimizing its generation assets.

### 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 the cost 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 commodity prices including electricity, natural gas, and coal. Other commodity-related operations include regulated sales of electricity to certain municipalities and large industrial customers and nonregulated retail gas marketing and coal mining operations. Open positions in terms of price, volume, and specified delivery points may occur and are managed using methods described below with frequent management reporting.

The Company's wholesale power marketing activities include asset optimization activities that manage the utilization of available electric generating capacity by entering into energy 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 accounts for asset optimization contracts that are derivatives at fair value with the offset marked to market through earnings.

The Company's other commodity-related operations involve the purchase and sale of commodities, including electricity, natural gas, and coal to meet customer demands and operational needs. These operations also enter into forward and option contracts that commit the Company to purchase and sell commodities in the future. Price risk from forward positions obligating the Company to deliver commodities is mitigated using stored inventory, generating capability, and offsetting forward purchase contracts. Price risk also results from forward contracts obligating the Company to purchase commodities to fulfill forecasted nonregulated sales of natural gas and coal that may, or may not, occur. With the exception of a small portion of contracts that are derivatives that qualify as hedges of forecasted transactions under SFAS 133, these contracts are expected to be settled by physical receipt or delivery of the commodity.

Market risk resulting from commodity contracts is measured by management using the potential impact on pre-tax earnings caused by the effect a 10% adverse change in forward commodity prices might have on market sensitive derivative positions outstanding on specific dates. For the years ended December 31, 2003, and 2002, a 10% adverse change in forward commodity prices would have decreased earnings by $3.0 million and $1.7 million, respectively, based upon open positions existing on the last day of those years.

### Commodity Price Risk from Unconsolidated Affiliate

ProLiance, a nonregulated energy marketing affiliate, engages in energy hedging activities to manage pricing decisions, minimize the risk of price volatility, and minimize price risk exposure in the energy markets. ProLiance's market exposure arises from storage inventory, imbalances, and fixed-price forward purchase and sale contracts, which are entered into to support its operating activities. Currently, ProLiance buys and sells physical commodities and utilizes financial instruments to hedge its market exposure. However, net open positions in terms of price, volume and specified delivery point do occur. ProLiance manages open positions with policies which limit its exposure to market risk and require reporting potential financial exposure to its management and its members.

**Interest Rate Risk**

The Company is exposed to interest rate risk associated with its borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on interest expense. The Company’s risk management objective is for between 20% and 30% of its total debt to be exposed to short-term interest rate volatility. However, there are times when this targeted range of interest rate exposure may not be attained. To manage this exposure, the Company may use derivative financial instruments. At December 31, 2003, such debt obligations, as affected by designated interest rate swaps, represented 24% of the Company's total debt portfolio.

Market risk is estimated as the potential impact resulting from fluctuations in interest rates on adjustable rate borrowing arrangements exposed to short-term interest rate volatility. During 2003 and 2002, the weighted average combined borrowings under these arrangements were $316.1 million and $311.3 million, respectively. At December 31, 2003, and 2002, combined borrowings under these arrangements were $328.3 million and $419.4 million, respectively. Based upon average borrowing rates under these facilities during the years ended December 31, 2003, and 2002, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by $3.2 million and $3.1 million, respectively.

**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. Credit risk associated with certain investments is also managed by a review of creditworthiness and receipt of collateral.

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. The Company mitigates these risks by executing derivative contracts that manage the price of forecasted natural gas purchases. These contracts are subject to regulation, which allows for reasonable and prudent hedging costs to be recovered through rates. When regulation is involved, SFAS 71 controls when the offset to mark-to-market accounting is recognized in earnings.

**ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

## MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Vectren Corporation 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 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, President, & Chief
Executive Officer
February 12, 2004

## INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors of Vectren Corporation:

We have audited the accompanying consolidated balance sheets of Vectren Corporation and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedules listed in the Index 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 Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, 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 consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 2-H, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards ("SFAS") 143, "Accounting for Asset Retirement Obligations." As discussed in Note 2-G, effective January 1, 2002, the Company adopted SFAS 142, "Goodwill and Other Intangibles." As discussed in Note 15, effective January 1, 2001, the Company adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

As discussed in Note 15, in 2003 the Company adopted EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and "Not Held for Trading Purposes" as Defined in Issue No. 02-3." Amounts for the years 2002 and 2001 have been reclassified in the accompanying statements of income to conform to this new method of presentation.

/s/ DELOITTE & TOUCHE LLP

DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 12, 2004

**VECTREN CORPORATION AND SUBSIDIARY COMPANIES**
**CONSOLIDATED BALANCE SHEETS**
***(In millions)***

| | At December 31, 2003 | 2002 |
|---|---|---|
| **ASSETS** | | |
| Current Assets | | |
| Cash & cash equivalents | $ 15.3 | $ 25.1 |
| Accounts receivable - less reserves of $3.2 & $5.5, respectively | 137.3 | 154.4 |
| Accrued unbilled revenues | 137.8 | 116.1 |
| Inventories | 70.4 | 62.8 |
| Recoverable fuel & natural gas costs | 20.3 | 19.3 |
| Prepayments & other current assets | 131.1 | 87.7 |
| **Total current assets** | **512.2** | **465.4** |
| Utility Plant | | |
| Original cost | 3,250.7 | 3,042.2 |
| Less: accumulated depreciation & amortization | 1,247.0 | 1,179.0 |
| **Net utility plant** | **2,003.7** | **1,863.2** |
| Investments in unconsolidated affiliates | 176.1 | 153.3 |
| Other investments | 122.9 | 124.3 |
| Non-utility property - net | 222.3 | 228.0 |
| Goodwill - net | 205.0 | 205.0 |
| Regulatory assets | 89.6 | 75.8 |
| Other assets | 21.6 | 21.5 |
| **TOTAL ASSETS** | **$ 3,353.4** | **$ 3,136.5** |

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

**VECTREN CORPORATION AND SUBSIDIARY COMPANIES**
**CONSOLIDATED BALANCE SHEETS**
***(In millions)***

| | At December 31, 2003 | At December 31, 2002 |
|---|---|---|
| **LIABILITIES & SHAREHOLDERS' EQUITY** | | |
| Current Liabilities | | |
| Accounts payable | $ 85.3 | $ 101.7 |
| Accounts payable to affiliated companies | 86.4 | 86.4 |
| Accrued liabilities | 109.3 | 119.9 |
| Short-term borrowings | 274.9 | 399.5 |
| Current maturities of long-term debt | 15.0 | 39.8 |
| Long-term debt subject to tender | 13.5 | 26.6 |
| **Total current liabilities** | **584.4** | **773.9** |
| Long-term Debt - Net of Current Maturities & Debt Subject to Tender | 1,072.8 | 954.2 |
| Deferred Income Taxes & Other Liabilities | | |
| Deferred income taxes | 235.4 | 195.5 |
| Regulatory liabilities & other removal costs | 235.0 | 210.0 |
| Deferred credits & other liabilities | 153.6 | 130.8 |
| **Total deferred credits & other liabilities** | **624.0** | **536.3** |
| Minority Interest in Subsidiary | 0.3 | 1.9 |
| Commitments & Contingencies (Notes 3, 12-14) | | |
| Cumulative, Redeemable Preferred Stock of a Subsidiary | 0.2 | 0.3 |
| Common Shareholders' Equity | | |
| Common stock (no par value) – issued & outstanding 75.6 and 67.9, respectively | 520.4 | 350.0 |
| Retained earnings | 562.4 | 530.4 |
| Accumulated other comprehensive loss | (11.1) | (10.5) |
| **Total common shareholders' equity** | **1,071.7** | **869.9** |
| **TOTAL LIABILITIES & SHAREHOLDERS' EQUITY** | **$ 3,353.4** | **$ 3,136.5** |

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

## VECTREN CORPORATION AND SUBSIDIARY COMPANIES
## CONSOLIDATED STATEMENTS OF INCOME
***(In millions, except per share amounts)***

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| OPERATING REVENUES | | | |
| Gas utility | $ 1,112.3 | $ 908.0 | $ 1,019.6 |
| Electric utility | 335.7 | 328.6 | 308.5 |
| Energy services & other | 139.7 | 287.2 | 681.0 |
| **Total operating revenues** | **1,587.7** | **1,523.8** | **2,009.1** |
| OPERATING EXPENSES | | | |
| Cost of gas sold | 762.5 | 570.2 | 708.9 |
| Fuel for electric generation | 86.5 | 81.6 | 74.4 |
| Purchased electric energy | 16.2 | 16.8 | 14.2 |
| Cost of energy services & other | 103.7 | 249.4 | 640.9 |
| Other operating | 233.7 | 223.0 | 243.2 |
| Merger & integration costs | - | - | 2.8 |
| Restructuring costs | - | - | 19.0 |
| Depreciation & amortization | 128.7 | 119.6 | 124.1 |
| Taxes other than income taxes | 57.0 | 51.9 | 53.7 |
| Total operating expenses | 1,388.3 | 1,312.5 | 1,881.2 |
| **OPERATING INCOME** | **199.4** | **211.3** | **127.9** |
| OTHER INCOME | | | |
| Equity in earnings of unconsolidated affiliates | 12.2 | 9.1 | 13.4 |
| Other – net | 13.0 | 11.5 | 16.7 |
| Total other income | 25.2 | 20.6 | 30.1 |
| Interest expense | 75.6 | 78.5 | 83.2 |
| **INCOME BEFORE INCOME TAXES** | **149.0** | **153.4** | **74.8** |
| Income taxes | 37.7 | 38.9 | 14.1 |
| Minority interest in & preferred dividend requirements of subsidiaries | 0.1 | 0.5 | 1.4 |
| **INCOME BEFORE EXTRAORDINARY LOSS & CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE** | **111.2** | **114.0** | **59.3** |
| Extraordinary loss – net of tax | - | - | (7.7) |
| Cumulative effect of change in accounting principle – net of tax | - | - | 1.1 |
| **NET INCOME** | **$ 111.2** | **$ 114.0** | **$ 52.7** |
| AVERAGE COMMON SHARES OUTSTANDING | 70.6 | 67.6 | 66.7 |
| DILUTED COMMON SHARES OUTSTANDING | 70.8 | 67.9 | 66.9 |
| EARNINGS PER SHARE OF COMMON STOCK: | | | |
| <u>BASIC</u> | | | |
| INCOME BEFORE EXTRAORDINARY LOSS & CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE | $ 1.58 | $ 1.69 | $ 0.89 |
| Extraordinary loss – net of tax | - | - | (0.12) |
| Cumulative effect of change in accounting principle – net of tax | - | - | 0.02 |
| **BASIC EARNINGS PER SHARE OF COMMON STOCK** | **$ 1.58** | **$ 1.69** | **$ 0.79** |
| <u>DILUTED</u> | | | |
| INCOME BEFORE EXTRAORDINARY LOSS & CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE | $ 1.57 | $ 1.68 | $ 0.89 |
| Extraordinary loss – net of tax | - | - | (0.12) |
| Cumulative effect of change in accounting principle – net of tax | - | - | 0.02 |
| **DILUTED EARNINGS PER SHARE OF COMMON STOCK** | **$ 1.57** | **$ 1.68** | **$ 0.79** |

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

## VECTREN CORPORATION AND SUBSIDIARY COMPANIES
## CONSOLIDATED STATEMENTS OF CASH FLOWS
***(In millions)***

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | $ 111.2 | $ 114.0 | $ 52.7 |
| Adjustments to reconcile net income to cash from operating activities: | | | |
| Depreciation & amortization | 128.7 | 119.6 | 124.1 |
| Deferred income taxes & investment tax credits | 35.1 | (28.5) | 12.4 |
| Equity in earnings of unconsolidated affiliates | (12.2) | (9.1) | (13.4) |
| Net unrealized (gain) loss on derivative instruments, including cumulative effect of change in accounting principle | (0.7) | 3.6 | (3.3) |
| Extraordinary loss on sale of leveraged leases - net of tax | - | - | 7.7 |
| Pension & postretirement periodic benefit cost | 13.8 | 13.2 | 8.5 |
| Other non-cash charges - net | (0.1) | 7.5 | 13.1 |
| Changes in working capital accounts: | | | |
| Accounts receivable & accrued unbilled revenue | (16.1) | (42.0) | 135.5 |
| Inventories | (7.6) | 0.4 | 24.2 |
| Recoverable fuel & natural gas costs | (1.0) | 48.1 | 25.9 |
| Prepayments & other current assets | (42.5) | 31.2 | (70.3) |
| Accounts payable, including to affiliated companies | (16.4) | 40.7 | (120.6) |
| Accrued liabilities | (8.4) | 11.7 | (7.0) |
| Changes in noncurrent assets | (3.9) | (6.0) | 4.6 |
| Changes in noncurrent liabilities | (2.8) | (12.1) | (6.0) |
| **Net cash flows from operating activities** | **177.1** | **292.3** | **188.1** |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Proceeds from: | | | |
| Long-term debt - net of issuance costs | 202.9 | - | 344.0 |
| Common stock - net of issuance costs | 163.2 | - | 129.4 |
| Stock option exercises & other stock plans | 7.1 | 1.3 | - |
| Requirements for: | | | |
| Dividends on common stock | (79.2) | (72.3) | (69.5) |
| Retirement of long-term debt | (121.9) | (6.5) | (7.6) |
| Redemption of preferred stock of subsidiary | (0.1) | (0.2) | (17.7) |
| Retirement of short-term notes payable | - | - | (150.0) |
| Dividends on preferred stock of subsidiary | - | - | (0.8) |
| Net change in short-term borrowings | (124.6) | 20.3 | (228.2) |
| Other activity | (1.6) | (0.2) | (2.3) |
| **Net cash flows from financing activities** | **45.8** | **(57.6)** | **(2.7)** |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Proceeds from: | | | |
| Unconsolidated affiliate distributions | 14.1 | 7.4 | 22.5 |
| Sale of leveraged lease investments | - | - | 53.8 |
| Notes receivable & other collections | 14.4 | 3.9 | 16.6 |
| Requirements for: | | | |
| Capital expenditures, excluding AFUDC equity | (236.2) | (218.7) | (239.7) |
| Unconsolidated affiliate investments | (16.6) | (12.5) | (22.7) |
| Notes receivable & other investments | (8.4) | (14.7) | (6.1) |
| **Net cash flows from investing activities** | **(232.7)** | **(234.6)** | **(175.6)** |
| Net (decrease) increase in cash & cash equivalents | (9.8) | 0.1 | 9.8 |
| Cash & cash equivalents at beginning of period | 25.1 | 25.0 | 15.2 |
| Cash & cash equivalents at end of period | $ 15.3 | $ 25.1 | $ 25.0 |
| Cash paid during the year for: | | | |
| Interest | $ 70.9 | $ 67.1 | $ 74.9 |
| Income taxes | 33.9 | 16.5 | 38.0 |

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

## VECTREN CORPORATION AND SUBSIDIARY COMPANIES
## CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
***(In millions, except per share amounts)***

| | Common Stock | | | | | |
|---|---|---|---|---|---|---|
| | Shares | Amount | Restricted Stock Grants | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
| **Balance at January 1, 2001** | **61.4** | **$ 219.3** | **$ (1.5)** | **$ 508.1** | **$ 7.5** | **$ 733.4** |
| Comprehensive income: | | | | | | |
| Net income | | | | 52.7 | | 52.7 |
| Minimum pension liability adjustments & other - net of tax | | | | | (1.8) | (1.8) |
| Comprehensive loss of unconsolidated affiliates - net of tax | | | | | (1.6) | (1.6) |
| Total comprehensive income | | | | | | 49.3 |
| Common stock: | | | | | | |
| Public issuance - net of $5.1 million of issuance costs | 6.3 | 129.4 | | | | 129.4 |
| Stock option exercises & other stock plans | - | (0.1) | (1.0) | (2.2) | | (3.3) |
| Dividends ($1.03 per share) | | | | (69.5) | | (69.5) |
| **Balance at December 31, 2001** | **67.7** | **348.6** | **(2.5)** | **489.1** | **4.1** | **839.3** |
| Comprehensive income: | | | | | | |
| Net income | | | | 114.0 | | 114.0 |
| Minimum pension liability adjustments & other - net of tax | | | | | (9.3) | (9.3) |
| Comprehensive loss of unconsolidated affiliates - net of tax | | | | | (5.3) | (5.3) |
| Total comprehensive income | | | | | | 99.4 |
| Common stock: | | | | | | |
| Stock option exercises & other stock plans | 0.1 | 1.3 | | | | 1.3 |
| Dividends ($1.07 per share) | | | | (72.3) | | (72.3) |
| Other | 0.1 | 2.4 | 0.2 | (0.4) | | 2.2 |
| **Balance at December 31, 2002** | **67.9** | **352.3** | **(2.3)** | **530.4** | **(10.5)** | **869.9** |
| Comprehensive income: | | | | | | |
| Net income | | | | 111.2 | | 111.2 |
| Minimum pension liability adjustments & other - net of tax | | | | | (6.3) | (6.3) |
| Comprehensive income of unconsolidated affiliates - net of tax | | | | | 5.7 | 5.7 |
| Total comprehensive income | | | | | | 110.6 |
| Common stock: | | | | | | |
| Public issuance - net of $6.2 million of issuance costs | 7.4 | 163.2 | | | | 163.2 |
| Stock option exercises & other stock plans | 0.3 | 7.1 | | | | 7.1 |
| Dividends ($1.11 per share) | | | | (79.2) | | (79.2) |
| Other | - | 0.3 | (0.2) | | | 0.1 |
| **Balance at December 31, 2003** | **75.6** | **$ 522.9** | **$ (2.5)** | **$ 562.4** | **$ (11.1)** | **$ 1,071.7** |

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

## VECTREN CORPORATION AND SUBSIDIARY COMPANIES
## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### 1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, 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, Inc. (Indiana Energy) and SIGCORP, Inc. (SIGCORP). On March 31, 2000, the merger of Indiana Energy with SIGCORP and into Vectren was consummated with a tax-free exchange of shares that has been accounted for as a pooling-of-interests in accordance with APB Opinion No. 16 "Business Combinations" (APB 16).

The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (VUHI), serves as the intermediate holding company for its three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), formerly a wholly owned subsidiary of Indiana Energy, Southern Indiana Gas and Electric Company (SIGECO), formerly a wholly owned subsidiary of SIGCORP, and the Ohio operations. VUHI also has other assets that provide information technology and other services to the three utilities. 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.

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, owned as a tenancy in common by Vectren Energy Delivery of Ohio, Inc. (VEDO), a wholly owned subsidiary, (53% ownership) and Indiana Gas (47% ownership), provide natural gas distribution and transportation services to 17 counties in west central Ohio, including counties surrounding Dayton.

The Company is also involved in nonregulated activities in four primary business areas: Energy Marketing and Services, Coal Mining, Utility Infrastructure Services, and Broadband. Energy Marketing and Services markets natural gas and provides energy management services, including energy performance contracting services. Coal Mining mines and sells coal and generates IRS Code Section 29 investment tax credits relating to the production of coal-based synthetic fuels. Utility Infrastructure Services provides underground construction and repair, facilities locating, and meter reading services. Broadband invests in broadband communication services such as analog and digital cable television, high-speed Internet and data services, and advanced local and long distance phone services. In addition, the nonregulated group has other businesses that provide utility services, municipal broadband consulting, and retail products and services, and that invest in energy-related opportunities, real estate and leveraged leases. The Nonregulated Group supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, utility infrastructure services, and other services.

### 2. Summary of Significant Accounting Policies

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

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.

C. Inventories

*Inventories* consist of the following:

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Gas in storage – at LIFO cost | $ 21.9 | $ 25.4 |
| Materials & supplies | 22.6 | 19.7 |
| Fuel (coal & oil) for electric generation | 14.0 | 11.3 |
| Gas in storage – at average cost | 7.2 | 3.2 |
| Other | 4.7 | 3.2 |
| **Total inventories** | **$ 70.4** | **$ 62.8** |

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, 2003, and 2002, by approximately $52.2 million and $32.7 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)* | 2003 | | 2002 | |
| | Original Cost | Depreciation Rates as a Percent of Original Cost | Original Cost | Depreciation Rates as a Percent of Original Cost |
| Gas utility plant | $ 1,721.9 | 3.6% | $ 1,622.0 | 3.8% |
| Electric utility plant | 1,322.4 | 3.4% | 1,216.1 | 3.3% |
| Common utility plant | 44.3 | 2.7% | 41.6 | 2.6% |
| Construction work in progress | 162.1 | - | 162.5 | - |
| **Total original cost** | **$ 3,250.7** | | **$ 3,042.2** | |

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)* | 2003 | 2002 | 2001 |
| AFUDC – borrowed funds | $ 2.1 | $ 3.1 | $ 2.1 |
| AFUDC – equity funds | 2.9 | 2.2 | 2.5 |
| **Total AFUDC capitalized** | **$ 5.0** | **$ 5.3** | **$ 4.6** |

Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred unless deferral is authorized by a rate order. When property that represents a retirement unit is replaced or removed, the cost of such property is charged to *Utility plant*, with an offsetting charge to *Accumulated depreciation* and *Regulatory liabilities* for the cost of removal.

E. Non-utility Property

*Non-utility property*, net of accumulated depreciation and amortization, by operating segment follows:

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Utility Group | | |
| Other Operations | $ 135.7 | $ 133.8 |
| Gas & Electric Utility Services | 5.6 | 5.4 |
| Nonregulated Group | 79.9 | 78.8 |
| Corporate & Other Group | 1.1 | 10.0 |
| **Non-utility property - net** | **$ 222.3** | **$ 228.0** |

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 or units-of-production method of amortization. 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 $84.5 million and $104.7 million as of December 31, 2003, and 2002, respectively. For the years ended December 31, 2003, 2002, and 2001, the Company capitalized interest totaling $0.5 million, $0.4 million, and $1.7 million, respectively, on non-utility plant construction projects.

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 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 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 business combinations is accounted for in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). The Company adopted SFAS 142 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.

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 extraordinary loss and cumulative effect of change in accounting principle* and *Net income* would have been $62.3 million and $55.7 million, respectively, 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, and no impairment charges have been recorded since adoption. The impairment test is performed at the beginning of each year.

Following is a reconciliation of reported net income and earnings per share to the adjusted net income disclosed above and related earnings per share for year ended December 31, 2001:

| | Year Ended December 31, 2001 | | |
|---|---|---|---|
| *(In millions, except per share amounts)* | Net Income | Basic EPS | Diluted EPS |
| As Reported | $ 52.7 | $ 0.79 | $ 0.79 |
| Add: goodwill amortization - net of tax | 3.0 | 0.05 | 0.05 |
| **As adjusted** | **$ 55.7** | **$ 0.84** | **$ 0.84** |

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 expenditures by the Company for removal costs or 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:

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Future amounts recoverable from ratepayers: | | |
| Income taxes | $ 18.1 | $ 15.8 |
| Other | 1.0 | - |
| | 19.1 | 15.8 |
| Amounts deferred for future recovery: | | |
| Demand side management programs | 25.0 | 23.8 |
| Other | 5.3 | 3.7 |
| | 30.3 | 27.5 |
| Amounts currently recovered through base rates: | | |
| Unamortized debt issue costs | 21.4 | 19.5 |
| Premiums paid to reacquire debt | 7.4 | 4.1 |
| Demand side management programs | 2.7 | 3.2 |
| | 31.5 | 26.8 |
| Amounts currently recovered through tracking mechanisms: | | |
| Ohio authorized trackers | 7.5 | 5.7 |
| Indiana authorized trackers | 1.2 | - |
| | 8.7 | 5.7 |
| **Total regulatory assets** | **$ 89.6** | **$ 75.8** |

The $31.5 million currently being recovered through base rates is earning a return with a weighted average recovery period of 18.2 years. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable.

*Regulatory liabilities & other removal costs* consist of the following:

| | At December 31, | | | |
|---|---|---|---|---|
| *(In millions)* | | 2003 | | 2002 |
| Cost of removal | $ | 228.8 | $ | - |
| Interest rate hedging proceeds (See Note 15) | | 6.2 | | - |
| **Total regulatory liabilities** | | **235.0** | | **-** |
| Other removal costs | | - | | 210.0 |
| **Total regulatory liabilities & other removal costs** | **$** | **235.0** | **$** | **210.0** |

*SFAS 143 & Other Removal Costs*
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. The Company adopted this statement on January 1, 2003. The adoption was not material to the Company's results of operations.

The Company collects an estimated cost of removal of its utility plant through depreciation rates established by regulatory proceedings. As of December 31, 2003, and 2002, such removal costs approximated $229 million and $210 million, respectively. In 2002, the cost of removal has been included in *Other removal costs,* which is in noncurrent liabilities. In 2003, the Company re-characterized other removal costs to *Regulatory liabilities* upon adoption of SFAS 143.

*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 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 Shareholders' Equity.

A summary of the components of and changes in *Accumulated other comprehensive income* for the past three years follows:

| | 2001 | | | 2002 | | 2003 | |
|---|---|---|---|---|---|---|---|
| *(In millions)* | Beginning of Year Balance | Changes During Year | End of Year Balance | Changes During Year | End of Year Balance | Changes During Year | End of Year Balance |
| Unconsolidated affiliates | $ 7.5 | $ (1.6) | $ 5.9 | $ (5.3) | $ 0.6 | $ 5.7 | $ 6.3 |
| Minimum pension liability | - | (2.4) | (2.4) | (9.2) | (11.6) | (5.8) | (17.4) |
| Other | - | 0.6 | 0.6 | (0.1) | 0.5 | (0.5) | - |
| **Accumulated other comprehensive income (loss)** | **$ 7.5** | **$ (3.4)** | **$ 4.1** | **$ (14.6)** | **$ (10.5)** | **$ (0.6)** | **$ (11.1)** |

Accumulated other comprehensive income arising from unconsolidated affiliates is the Company's portion of ProLiance Energy, LLC's and Reliant Services, LLC's accumulated comprehensive income related to its adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) and continued use of cash flow hedges, including commodity contracts and interest rate swaps, and the Company's portion of Haddington Energy Partners, LP's accumulated comprehensive income related to unrealized gains and losses of "available for sale securities." (See Note 3 for more information on unconsolidated affiliates.)

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 Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $37.1 million in 2003, $32.4 million in 2002, and $26.6 million in 2001. Excise and utility receipts taxes paid are recorded as a component of *Taxes other than income taxes*.

L. Other Significant Policies

Included elsewhere in these Notes are significant accounting policies related to investments in unconsolidated affiliates (Note 3), income taxes (Note 5), earnings per share (Note 10), and derivatives (Note 15).

As more fully described in Note 11, the Company applies the intrinsic method prescribed in APB Opinion 25, "Accounting for Stock Issued to Employees" (APB 25) and related interpretations when measuring compensation expense for its equity-based compensation plans. The exercise price of stock options awarded under the Company's stock option plans is equal to the fair market value of the underlying common stock on the date of grant. Accordingly, no compensation expense has been recognized for stock option plans. The Company also maintains restricted stock and phantom stock plans for executives and non-employee directors that result in equity-based compensation expense recognized in reported net income consistent with expense that would have been recognized if the Company used the fair value based method prescribed in SFAS No. 123 "Accounting for Stock-Based Compensation" (SFAS 123).

Following is the effect on net income and earnings per share as if the fair value based method prescribed in SFAS 123 had been applied to the Company's equity-based compensation plans:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions, except per share amounts)* | 2003 | 2002 | 2001 |
| Net Income: | | | |
| As reported | $ 111.2 | $ 114.0 | $ 52.7 |
| Add: Equity-based employee compensation included in reported net income- net of tax | 2.1 | 1.3 | 1.7 |
| Deduct: Total equity-based employee compensation expense determined under fair value based method for all awards- net of tax | 3.4 | 2.1 | 2.8 |
| **Pro forma** | **$ 109.9** | **$ 113.2** | **$ 51.6** |
| Basic Earnings Per Share: | | | |
| As reported | $ 1.58 | $ 1.69 | $ 0.79 |
| Pro forma | 1.56 | 1.68 | 0.77 |
| Diluted Earnings Per Share: | | | |
| As reported | $ 1.57 | $ 1.68 | $ 0.79 |
| Pro forma | 1.55 | 1.67 | 0.77 |

M. 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.

N. Reclassification
Certain prior year amounts have been reclassified in the consolidated financial statements and accompanying notes to conform to 2003 classifications.

## 3. Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates where the Company has significant influence are accounted for using the equity method of accounting. The Company's share of net income or loss from these investments is recorded in *Equity in earnings of unconsolidated affiliates*. Dividends are recorded as a reduction of the carrying value of the investment when received. Investments in unconsolidated affiliates where the Company does not have significant influence are accounted for using the cost method of accounting less write-downs for declines in value judged to be other than temporary. Dividends are recorded as *Other - net* when received.

*Investments in unconsolidated affiliates* consist of the following:

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| ProLiance Energy, LLC | $ 84.7 | $ 61.4 |
| Haddington Energy Partnerships | 26.3 | 19.7 |
| Reliant Services, LLC | 19.2 | 18.4 |
| Utilicom Networks, LLC & related entities | 15.4 | 15.4 |
| Pace Carbon Synfuels, LP | 8.7 | 6.8 |
| Other partnerships & corporations | 21.8 | 31.6 |
| **Total investments in unconsolidated affiliates** | **$ 176.1** | **$ 153.3** |

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.

Pre-tax income of $25.9 million, $19.1 million, and $12.8 million was recognized as ProLiance's contribution to earnings for the years ended December 31, 2003, 2002, and 2001, respectively.

*Integration of SIGCORP Energy Services, LLC and ProLiance Energy, LLC*

In June 2002, the integration of Vectren's wholly owned subsidiary SIGCORP Energy Services, LLC (SES) with ProLiance was completed. SES provided natural gas and related services to SIGECO and others prior to the integration. In exchange for the contribution of SES' net assets totaling $19.2 million, including cash of $2.0 million, Vectren's allocable share of ProLiance's profits and losses increased from 52.5% to 61%, consistent with Vectren's new ownership percentage. In March 2001, Vectren's allocable share of profits and losses increased from 50% to 52.5% when ProLiance began managing the Ohio operations' gas portfolio. Governance and voting rights remain at 50% for each member; and therefore, Vectren continues to account for its investment in ProLiance using the equity method of accounting.

Prior to June 1, 2002, SES' operating results were consolidated. Subsequent to June 1, 2002, SES' operating results, now part of ProLiance, are reflected in equity in earnings of unconsolidated affiliates. The transfer of net assets was accounted for at book value consistent with joint venture accounting and did not result in any gain or loss. Additionally, the non-cash component of the transfer totaling $17.2 million is excluded from the Consolidated Statement of Cash Flows.

*Transactions with ProLiance*

Purchases from ProLiance for resale and for injections into storage for the years ended December 31, 2003, 2002, and 2001, totaled $797.7 million, $544.1 million, and $610.6 million, respectively. Amounts owed to ProLiance at December 31, 2003, and 2002, for those purchases were $86.0 million and $84.6 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.

*Summarized Financial Information*

For the year ended December 31, 2003, ProLiance's revenues, margin, operating income, and net income were (in millions) $2,269.7, $71.5, $43.3, and $42.5, respectively. For the year ended December 31, 2002, revenues, margin, operating income, and net income were (in millions) $1,534.5, $61.1, $36.5, and $37.4, respectively. For the year ended December 31, 2001, revenues, margin, operating income, and net income were (in millions) $1,599.5, $40.9, $26.1, and $27.7, respectively. As of December 31, 2003, current assets, noncurrent assets, current liabilities, and noncurrent liabilities were (in millions) $467.7, $22.2, $346.0, and $7.8, respectively. As of December 31, 2002, current assets, noncurrent assets, current liabilities, and noncurrent liabilities were (in millions) $301.6, $22.8, $228.8, and $1.2, respectively.

*ProLiance Contingency*

There is currently a lawsuit pending in the United States District Court for the Northern District of Alabama filed by the City of Huntsville, Alabama d/b/a Huntsville Utilities, Inc. (Huntsville Utilities) against ProLiance. Huntsville Utilities asserts claims based on negligent provision of portfolio services and/or pricing advice, fraud, fraudulent inducement, and other theories. These claims relate generally to several basic arguments: (1) negligence in providing advice and/or administering portfolio arrangements; (2) alleged promises to provide gas at a below-market rate; (3) the creation and repayment of a "winter levelizing program" instituted by ProLiance in conjunction with the Manager of Huntsville's Gas Utility, to allow Huntsville Utilities to pay its gas bills over an extended period of time coupled with the alleged ignorance about the program on the part of Huntsville Utilities' Gas Board, and; (4) the sale of Huntsville Utilities' gas storage supplies to repay the balance owed on the winter levelizing program and the authority of Huntsville Utilities' gas manager to approve those sales. In a press conference on May 21, 2002, Huntsville Utilities asserted its monetary damages to be approximately $10 million, and seeks to treble that amount. ProLiance has made counterclaims asserting breach of contract, among others, based on

Huntsville Utilities' refusal to take gas under fixed price agreements. Both parties have denied the charges contained in the respective claims.

In 2003, ProLiance established reserves for amounts due from Huntsville Utilities due to uncertainties surrounding collection. ProLiance denies any wrongdoing, believes its actions were proper under the contract and amendments signed by the manager of Huntsville's Gas Utility, and is vigorously defending against the suit. ProLiance is an insured under a policy of insurance providing defense costs which may provide in whole or in part, indemnification within the policy limits for claims asserted against ProLiance. Accordingly, no other loss contingencies have been recorded at this time. However, it is not possible to predict or determine the outcome of this litigation and accordingly there can be no assurance that ProLiance will prevail. It is not currently expected that costs associated with this matter will have a material adverse effect on Vectren's consolidated financial position or liquidity but an unfavorable outcome could possibly be material to Vectren's earnings.

Haddington Energy Partnerships

The Company has an approximate 40% ownership interest in Haddington Energy Partners, LP (Haddington I). Haddington I raised $27.0 million to invest in energy projects. In July 2000, the Company made a commitment to fund an additional $20.0 million in Haddington Energy Partners II, LP (Haddington II), which raised a total of $47.0 million in firm commitments. Haddington II provides additional capital for Haddington I portfolio companies and made investments in new areas, such as distributed generation, power backup and quality devices, and emerging technologies such as microturbines and photovoltaics. At December 31, 2003, $7.7 million of the additional $20.0 million commitment remains. The Company has an approximate 40% ownership interest in Haddington II. Both Haddington ventures are investment companies accounted for using the equity method of accounting. For the year ended December 31, 2001, the partnerships' contribution to the Company's pre-tax earnings was $6.2 million. In 2002 and 2003, the earnings contribution was not significant.

The following is summarized financial information as to the assets, liabilities, and results of operations of the Haddington Partnerships. For the year ended December 31, 2003, revenues, operating income, and net income were (in millions) $0.6, ($0.3), and ($0.3), respectively. For the year ended December 31, 2002, revenues, operating income, and net income were (in millions) zero, ($0.9), and ($0.9), respectively. For the year ended December 31, 2001, revenues, operating income, and net income were (in millions) $23.6, $22.5, and $22.5, respectively. As of December 31, 2003, investments, other assets, and liabilities were (in millions) $64.4, $1.0, and zero, respectively. As of December 31, 2002, investments, other assets, and liabilities were (in millions) $49.6, $0.3, and zero, respectively.

Utilicom Networks, LLC & Related Entities

Utilicom Networks, LLC (Utilicom) is a provider of bundled communication services through high capacity broadband networks, including analog and digital cable television, high-speed Internet, and advanced local and long distance phone services. The Company has an approximate 2% equity and a convertible subordinated debt investment in Utilicom. The Company also has an approximate 19% equity interest in SIGECOM Holdings, Inc. (Holdings), which was formed by Utilicom to hold interests in SIGECOM, LLC (SIGECOM). The Company accounts for its investments in Utilicom and Holdings using the cost method of accounting. SIGECOM provides broadband services to the greater Evansville, Indiana area.

Utilicom also plans to provide broadband services to the greater Indianapolis, Indiana and Dayton, Ohio markets. However, the funding of these projects has been delayed due to the continued difficult environment within the telecommunication capital markets, which has prevented Utilicom from obtaining debt financing on terms it considers acceptable. While the existing investors are still interested in the Indianapolis and Dayton markets, the Company is not required to make further investments and does not intend to proceed unless commitments are obtained to fully fund these projects. Franchising agreements have been extended in both locations.

At December 31, 2003, the Company has $32.3 million of notes receivable from Utilicom-related entities which are convertible into equity interests. Notes receivable totaling $30.1 million are convertible into Utilicom ownership at the Company's option or upon the event of a public offering of stock by Utilicom, and $2.2 million are convertible into common equity interests in the Indianapolis and Dayton ventures at the Company's option. Upon conversion, the Company would have up to an approximate 16% interest in Utilicom, assuming completion of all required funding and up to a 31% interest in the Indianapolis and Dayton ventures. Investments in convertible notes receivable are included in *Other investments*.

At December 31, 2003, and 2002, the Company's combined investment in equity and debt securities of Utilicom-related entities totaled $47.7 million and $46.1 million, respectively. These investments had no significant impact on the Company's financial results in 2003, 2002, or 2001.

Pace Carbon Synfuels, LP

Pace Carbon Synfuels, LP (Pace Carbon) is a Delaware limited partnership formed to develop, own, and operate four projects to produce and sell coal-based synthetic fuel (synfuel) utilizing Covol technology. The Company has an 8.3% interest in Pace Carbon which is accounted for using the equity method of accounting. Additional investments in Pace Carbon will be made to the extent Pace Carbon generates federal tax credits, with any such additional investments to be funded by these credits. The investment in Pace Carbon resulted in losses reflected in *Equity in earnings of unconsolidated affiliates* totaling $11.4 million, $6.8 million, and $4.5 million in 2003, 2002, and 2001, respectively. The production of synthetic fuel generates IRS Code Section 29 investment tax credits that are reflected in *Income taxes*. Net income, including the losses, tax benefits, and tax credits, generated from the investment in Pace Carbon totaled $10.3 million in 2003, $6.0 million in 2002, and $4.3 million in 2001.

The following is summarized financial information as to the assets, liabilities, and results of operations of Pace Carbon. For the year ended December 31, 2003, revenues, margin, operating loss, and net loss were (in millions) $254.2, ($90.7), ($121.3), and ($134.4), respectively. For the year ended December 31, 2002, revenues, margin, operating loss, and net loss were (in millions) $125.6, ($53.1), ($72.6), and ($73.4), respectively. For the year ended December 31, 2001, revenues, margin, operating loss, and net loss were (in millions) $86.2, ($25.1), ($44.1), and ($44.8), respectively. As of December 31, 2003, current assets, noncurrent assets, current liabilities, and noncurrent liabilities were (in millions) $37.0, $105.2, $25.9, and $58.4, respectively. As of December 31, 2002, current assets, noncurrent assets, current liabilities, and noncurrent liabilities were (in millions) $32.7, $44.8, $45.9 and $4.3, respectively.

IRS Section 29 Investment Tax Credit Recent Developments

Under Section 29 of the Internal Revenue Code, manufacturers such as Pace Carbon receive a tax credit for every ton of synthetic fuel sold. To qualify for the credits, the synthetic fuel must meet three primary conditions: 1) there must be a significant chemical change in the coal feedstock, 2) the product must be sold to an unrelated person, and 3) the production facility must have been placed in service before July 1, 1998.

In past rulings, the Internal Revenue Service (IRS) has concluded that the synthetic fuel produced at the Pace Carbon facilities should qualify for Section 29 tax credits. The IRS issued a private letter ruling with respect to the four projects on November 11, 1997, and subsequently issued an updated private letter ruling on September 23, 2002.

As a partner in Pace Carbon, Vectren has reflected total tax credits under Section 29 in its consolidated results through December 31, 2003, of approximately $39 million. Vectren has been in a position to fully utilize the credits generated and continues to project full utilization.

In June 2003, the IRS, in an industry-wide announcement, stated that it would review the scientific validity of test procedures and results presented as evidence of significant chemical change. During this review, the IRS suspended the issuance of new private letter rulings on that subject. In October 2003, the IRS completed its review and determined that the test procedures and results used by taxpayers are scientifically valid if the procedures are applied in a consistent and unbiased manner. Also, the IRS will issue new private letter rulings based on revised standards; however, it has continuing concerns regarding the sampling and data/record retention practices prevalent in the synthetic fuels industry.

During June 2001, the IRS began a tax audit of Pace Carbon for the 1998 tax year and later expanded the audit to include tax years 1999, 2000, and 2001. Based on conclusions reached in the industry-wide review and recently issued private letter rulings involving other synthetic fuel facilities, Vectren believes chemical change issues from these audits may soon be resolved. However, the IRS has not directly notified Pace Carbon of any resolution.

Vectren believes it is justified in its reliance on the private letter rulings for the Pace Carbon facilities, that the test results that Pace Carbon presented to the IRS in connection with its private letter rulings are scientifically valid, and that Pace Carbon has operated its facilities in compliance with its private letter rulings and Section 29 of the Internal Revenue Code. However, at this time, Vectren cannot provide any assurance as to the outcome of these audits concerning the issue of chemical change or any other issue raised during the audits relative to its investment in Pace Carbon. Further, it is expected that Section 29 investments will continue to draw attention from various interest groups.

Other Affiliate Transactions

The Company has ownership interests in other affiliated companies accounted for using the equity method of accounting that perform underground construction and repair, facilities locating, and meter reading services to the Company. For the years ended December 31, 2003, 2002, and 2001, fees for these services and construction-related expenditures paid by the Company to its affiliates totaled $37.2 million, $38.3 million, and $37.9 million, respectively. Amounts charged by these affiliates are market based. Amounts owed to unconsolidated affiliates other than ProLiance totaled $0.4 million and $1.8 million at December 31, 2003, and 2002, respectively, and are included in *Accounts payable to affiliated companies* in the Consolidated Balance Sheets. Amounts due from unconsolidated affiliates included in *Accounts receivable* totaled $0.4 million and $0.6 million, respectively, at December 31, 2003, and 2002.

**4. Other Investments**

Other investments consist of the following:

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Notes receivable: | | |
| Utilicom Networks, LLC & related entities | $ 32.3 | $ 30.7 |
| Other notes receivable | 32.4 | 41.8 |
| Total notes receivable | 64.7 | 72.5 |
| Leveraged leases | 32.2 | 30.5 |
| Other investments | 26.0 | 21.3 |
| **Total other investments** | **$ 122.9** | **$ 124.3** |

Notes Receivable

Interest on the notes receivable accrue at various rates up to 10%, and are due at various times through 2024. Generally, first or second mortgages and/or capital stock or partnership units serve as collateral for the notes. (See Note 3 regarding the convertibility of the Utilicom-related notes into equity interests.)

Leveraged Leases

The Company is a lessor in several leveraged lease agreements under which real estate or equipment is leased to third parties. The total equipment and facilities cost was approximately $76.2 million at both December 31, 2003, and 2002. The cost of the equipment and facilities was partially financed by non-recourse debt provided by lenders who have been granted an assignment of rentals due under the leases and a security interest in the leased property, which they accepted as their sole remedy in the event of default by the lessee. Such debt amounted to approximately $51.8 million and $51.7 million at December 31, 2003, and 2002, respectively.

The Company's net investment in leveraged leases follows:

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Minimum lease payments receivable | $ 49.3 | $ 48.6 |
| Estimated residual value | 22.0 | 22.0 |
| Less: Unearned income | 39.1 | 40.1 |
| Leveraged lease investments | 32.2 | 30.5 |
| Less: Deferred taxes arising from leveraged leases | 26.2 | 26.3 |
| **Net investment in leveraged leases** | **$ 6.0** | **$ 4.2** |

In June 2001, the Company sold certain leveraged lease investments with a net book value of $59.1 million at a loss of $12.4 million ($7.7 million after tax). Because of the transaction's significance and because the transaction occurred within two years of the effective date of the merger of Indiana Energy and SIGCORP, which was accounted for as a pooling-of-interests, APB 16 requires the loss on disposition of these investments to be treated as extraordinary. Proceeds from the sale totaled $46.7 million.

**5. Income Taxes**

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

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| Current: | | | |
| Federal | $ (11.9) | $ 62.2 | $ (2.2) |
| State | 14.5 | 5.2 | 3.9 |
| **Total current taxes** | **2.6** | **67.4** | **1.7** |
| Deferred: | | | |
| Federal | 39.1 | (26.2) | 14.9 |
| State | (1.8) | - | (0.2) |
| **Total deferred taxes** | **37.3** | **(26.2)** | **14.7** |
| Amortization of investment tax credits | (2.2) | (2.3) | (2.3) |
| **Total income tax expense** | **$ 37.7** | **$ 38.9** | **$ 14.1** |

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| Statutory rate | 35.0 % | 35.0 % | 35.0 % |
| State and local taxes-net of federal benefit | 5.5 | 2.4 | 3.0 |
| Section 29 tax credits | (11.7) | (7.0) | (9.5) |
| Amortization of investment tax credit | (1.5) | (1.5) | (3.1) |
| Other tax credits | (0.9) | (1.1) | (3.6) |
| All other-net | (1.1) | (2.4) | (2.6) |
| **Effective tax rate** | **25.3 %** | **25.4 %** | **19.2 %** |

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)* | 2003 | 2002 |
| Noncurrent deferred tax liabilities (assets): | | |
| Depreciation & cost recovery timing differences | $ 225.4 | $ 197.9 |
| Leveraged leases | 26.2 | 26.3 |
| Regulatory assets recoverable through future rates | 26.9 | 37.5 |
| Regulatory liabilities to be settled through future rates | (8.8) | (21.7) |
| Employee benefit obligations | (29.8) | (45.9) |
| Other – net | (4.5) | 1.4 |
| Net noncurrent deferred tax liability | 235.4 | 195.5 |
| Current deferred tax liabilities (assets): | | |
| Deferred fuel costs-net | 6.9 | 7.7 |
| Net current deferred tax liability | 6.9 | 7.7 |
| **Net deferred tax liability** | **$ 242.3** | **$ 203.2** |

At December 31, 2003, and 2002, investment tax credits totaling $16.4 million and $18.6 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 had no tax credit carryforwards at December 31, 2003, or 2002. Alternative Minimum Tax credit carryforwards of approximately $5.2 million were utilized in 2001. Through certain of its nonregulated subsidiaries and investments, the Company also realizes federal income tax credits associated with affordable housing projects and the production of synthetic fuels. During 2001, tax credit carryforwards from these operations totaling $5.5 million were utilized.

## 6. Retirement Plans & Other Postretirement Benefits

At December 31, 2003, the Company maintains three qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and three other postretirement benefit plans. The defined benefit pension and other postretirement benefit plans which cover eligible full-time regular employees are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The Company has Voluntary Employee Beneficiary Association (VEBA) Trust Agreements for the partial funding of postretirement health benefits for retirees and their eligible dependents and beneficiaries. Annual funding of the VEBA's is discretionary and is based on the projected cost over time of benefits to be provided to covered persons consistent with acceptable actuarial methods. To the extent these postretirement benefits are funded, the benefits are not liabilities in these consolidated financial statements. The detailed disclosures of benefit components that follow are based on an actuarial valuation using a measurement date as of September 30. The qualified pension plans and the SERP are aggregated under the heading "Pension Benefits." Other postretirement benefit plans are aggregated under the heading "Other Benefits."

FSP 106-1

The recently enacted Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Medicare Act) provides a prescription drug benefit as well as a federal subsidy to sponsors of certain retiree health care benefit plans. As allowed by FASB Staff Position No. 106-1 (FSP 106-1), the Company has elected to defer reflecting the effects of the Medicare Act on the accumulated benefit obligation and net periodic postretirement benefit cost in these financial statements and accompanying notes. The Company's deferral election expires upon the occurrence of any event that triggers a required remeasurement of plan assets or obligations, or upon the issuance of specific authoritative guidance on the accounting for the federal subsidy. Such guidance is pending and when issued could require the Company to adjust previously reported information.

Benefit Obligations
A reconciliation of the Company's benefit obligations at December 31, 2003, and 2002, follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2003 | 2002 |
| Benefit obligation, beginning of period | $ 201.9 | $ 191.3 | $ 81.5 | $ 83.6 |
| Service cost – benefits earned during the period | 5.8 | 5.9 | 0.9 | 1.0 |
| Interest cost on projected benefit obligation | 13.6 | 13.9 | 5.4 | 6.0 |
| Plan amendments | - | (0.1) | - | - |
| Benefits paid | (12.7) | (12.1) | (5.4) | (8.7) |
| Actuarial loss (gain) | 14.1 | 3.0 | 14.9 | (0.4) |
| **Benefit obligation, end of period** | **$ 222.7** | **$ 201.9** | **$ 97.3** | **$ 81.5** |

The accumulated benefit obligation for all defined benefit pension plans was $202.7 million and $179.1 million at December 31, 2003, and 2002, respectively.

The benefit obligation as of December 31, 2003, and 2002, was calculated using the following weighted average assumptions:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | 2003 | 2002 | 2003 | 2002 |
| Discount rate | 6.00% | 6.75% | 6.00% | 6.75% |
| Rate of compensation increase | 3.50% | 4.25% | 3.50% | 4.25% |

A 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004. The rate was assumed to decrease gradually to 5% for 2009 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one percentage point increase in assumed health care cost trend rates would have increased the benefit obligation by $8.4 million. A one percentage point decrease would have decreased the obligation by $7.0 million.

Plan Assets
A reconciliation of the Company's plan assets at December 31, 2003, and 2002, follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2003 | 2002 |
| Plan assets at fair value, beginning of period | $ 138.6 | $ 160.1 | $ 7.4 | $ 8.8 |
| Actual return on plan assets | 20.8 | (10.1) | 1.4 | (0.5) |
| Employer contributions | 1.1 | 0.7 | 5.8 | 7.8 |
| Benefits paid | (12.7) | (12.1) | (5.4) | (8.7) |
| **Fair value of plan assets, end of period** | **$ 147.8** | **$ 138.6** | **$ 9.2** | **$ 7.4** |

The asset allocation for the Company's pension and postretirement plans at the measurement date for 2003 and 2002, and the target allocation for 2004, by asset category, follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | 2003 | 2002 | 2003 | 2002 |
| Equity securities | 59% | 57% | 54% | 49% |
| Debt securities | 35% | 43% | 32% | 47% |
| Real estate | 6% | - | - | - |
| Short term investments & other | - | - | 14% | 4% |
| Total | 100% | 100% | 100% | 100% |

The Company invests in a master trust that benefits all qualified defined benefit pension plans. The general investment objectives are to invest in a diversified portfolio, comprised of both equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of 60% equities, 35% debt, and 5% real estate for 2004, and for postretirement plans of 55% equities, 35% debt, and 10% short-term investments and other for 2004. Objectives do not target a specific return by asset class. The portfolio's return is monitored in total and is designed to outperform inflation. These investment objectives are long-term in nature.

Funded Status

The funded status of the plans, reconciled to amounts reflected in the balance sheets as of December 31, 2003, and 2002, follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2003 | 2002 |
| Fair value of plan assets, end of period | $ 147.8 | $ 138.6 | $ 9.2 | $ 7.4 |
| Benefit obligation, end of period | (222.7) | (201.9) | (97.3) | (81.5) |
| **Funded status, end of period** | **(74.9)** | **(63.3)** | **(88.1)** | **(74.1)** |
| Unrecognized net loss (gain) | 49.4 | 42.2 | 1.7 | (13.0) |
| Unrecognized transitional (asset) obligation | (0.2) | (0.4) | 29.1 | 32.0 |
| Unrecognized prior service cost | 10.5 | 11.0 | - | - |
| Post measurement date adjustments | 0.2 | 0.2 | 0.8 | 2.9 |
| **Net amount recognized, end of year** | **$ (15.0)** | **$ (10.3)** | **$ (56.5)** | **$ (52.2)** |
| Net amount recognized included in: | | | | |
| *Deferred credits & other liabilities* | $ (18.9) | $ (15.2) | $ (56.5) | $ (52.2) |
| *Other assets* | 3.9 | 4.9 | - | - |

As of December 31, 2003, and 2002, the funded status of the SERP, which is included in Pension Benefits in the chart above, was an unfunded amount of $12.7 million and $11.9 million, respectively, and the net amount recognized in the balance sheet related to the SERP as of December 31, 2003, and 2002 was a liability of $7.8 million and $7.5 million, respectively.

At December 31, 2003, and 2002, all pension and postretirement plans had accumulated benefit obligations in excess of plan assets. As required by SFAS 87, the Company has recorded additional minimum pension liability adjustments to reflect the total unfunded accumulated liability arising from its pension plans. This additional minimum pension liability adjustment is included in *Deferred credits & other liabilities.* The offset to this additional liability is recorded to an intangible asset included in *Other assets* to the extent pension plans have unrecognized prior service cost. Any unfunded or unaccrued amount in excess of prior service cost is recorded in net of tax amounts to *Accumulated other comprehensive income* in shareholders' equity. The effects of additional minimum pension liability adjustments at December 31, 2003, and 2002, follow:

| *(In millions)* | 2003 | 2002 |
|---|---|---|
| Minimum pension liability adjustment, beginning of year | $ 30.0 | $ 7.3 |
| Change in minimum pension liability adjustment included in: | | |
| Other comprehensive income before effect of taxes | 9.7 | 15.7 |
| Other assets | - | 7.0 |
| **Minimum pension liability adjustment, end of year** | **$ 39.7** | **$ 30.0** |
| Offset included in: | | |
| *Accumulated other comprehensive income* | $ 17.4 | $ 11.6 |
| *Other assets* | 10.5 | 10.5 |
| *Deferred income taxes* | 11.8 | 7.9 |

Expected Cash Flows

In 2004, the Company expects to make contributions of approximately $5.3 million to its pension plan trusts. In addition, the Company expects to make payments totaling $0.8 million directly to SERP participants and $4.9 million directly to those participating in other postretirement plans.

Expected retiree pension benefit payments, including the SERP, projected to be required during the years following 2003 (in millions) are $10.5 in 2004, $10.8 in 2005, $11.2 in 2006, $11.7 in 2007, $12.2 in 2008 and $73.1 in years 2009-2013. Expected benefit payments projected to be required for postretirement benefits during the years following 2003 (in millions) are $5.2 in 2004, $5.5 in 2005, $5.8 in 2006, $6.0 in 2007, $6.3 in 2008 and $33.8 in years 2009-2013.

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost for the three years ended December 31, 2003, follows:

| | Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| Service cost | $ 5.8 | $ 5.9 | $ 5.9 | $ 0.9 | $ 1.0 | $ 1.0 |
| Interest cost | 13.6 | 13.9 | 13.6 | 5.4 | 6.0 | 5.8 |
| Expected return on plan assets | (14.8) | (15.7) | (16.3) | (0.7) | (0.7) | (0.8) |
| Amortization of prior service cost | 0.8 | 0.8 | 0.8 | - | - | - |
| Amortization of transitional (asset) obligation | (0.2) | (0.5) | (0.6) | 2.9 | 2.9 | 3.0 |
| Amortization of actuarial loss (gain) | 0.5 | 0.1 | (0.9) | (0.5) | (0.5) | (1.0) |
| Settlement, curtailment, & other charges (credits) | - | - | (1.4) | - | - | (0.6) |
| **Net periodic benefit cost** | **$ 5.7** | **$ 4.5** | **$ 1.1** | **$ 8.0** | **$ 8.7** | **$ 7.4** |

To calculate the expected return on plan assets, the Company uses the plan assets' market-related value and an expected long-term rate of return. The fair market value of the assets at the measurement date is adjusted to a market-related value by recognizing the change in fair value experienced in a given year ratably over a five-year period. The expected long-term rate of return has not been adjusted for plan expenses. An estimate of plan expenses is included in the service cost component of net periodic benefit cost.

Based on a targeted 60% equity, 35% debt, and 5% real estate allocation for the pension plans, the Company has used a long-term expected rate of return of 9.0% to calculate 2003 periodic benefit cost. For fiscal 2004, the expected long-term rate of return will be 8.5%.

The weighted averages of significant assumptions used to determine net periodic benefit costs follow:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | 2003 | 2002 | 2003 | 2002 |
| Equity securities | 59% | 57% | 54% | 49% |
| Debt securities | 35% | 43% | 32% | 47% |
| Real estate | 6% | - | - | - |
| Short term investments & other | - | - | 14% | 4% |
| Total | 100% | 100% | 100% | 100% |

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one percentage point increase in assumed health care cost trend rates would have increased the service and interest cost components of pension costs by $0.7 million. A one percentage point decrease would have decreased the benefit costs by $0.6 million.

Defined Contribution Plan

The Company also has defined contribution retirement savings plans that are qualified under sections 401(a) and 401(k) of the Internal Revenue Code. During 2003, 2002, and 2001, the Company made contributions to these plans of $3.6 million, $3.0 million, and $3.4 million, respectively.

## 7. Borrowing Arrangements

Short-Term Borrowings

At December 31, 2003, the Company has $531 million of short-term borrowing capacity, including $351 million for the Utility Group operations and $180 million for the wholly owned Nonregulated Group and corporate operations, of which approximately $166 million is available for the Utility Group operations and approximately $91 million is available for wholly owned Nonregulated Group and corporate operations. The availability of short-term borrowing is reduced by outstanding letters of credit totaling $1.0 million, collateralizing Nonregulated Group activities. See the table below for interest rates and outstanding balances.

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| Weighted average commercial paper and bank loans outstanding during the year | $ 296.9 | $ 288.8 | $ 447.0 |
| Weighted average interest rates during the year | | | |
| Commercial paper | 1.36% | 2.02% | 4.39% |
| Bank loans | 1.94% | 2.52% | 6.77% |

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Commercial paper | $ 184.4 | $ 239.1 |
| Bank loans | 88.4 | 157.8 |
| Other | 2.1 | 2.6 |
| **Total short-term borrowings** | **$ 274.9** | **$ 399.5** |

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

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| **Vectren Capital Corp.** | | |
| Fixed Rate Senior Unsecured Notes | | |
| 2005, 7.67% | $ 38.0 | $ 38.0 |
| 2007, 7.83% | 17.5 | 17.5 |
| 2010, 7.98% | 22.5 | 22.5 |
| 2012, 7.43% | 35.0 | 35.0 |
| **Total Vectren Capital Corp.** | **113.0** | **113.0** |
| **VUHI** | | |
| Fixed Rate Senior Unsecured Notes | | |
| 2011, 6.625% | 250.0 | 250.0 |
| 2013, 5.25% | 100.0 | - |
| 2018, 5.75% | 100.0 | - |
| 2031, 7.25% | 100.0 | 100.0 |
| **Total VUHI** | **550.0** | **350.0** |
| **SIGECO** | | |
| First Mortgage Bonds | | |
| 2003, 1978 Series B, 6.25%, tax exempt | - | 1.0 |
| 2016, 1986 Series, 8.875% | 13.0 | 13.0 |
| 2023, Series, 7.60% | - | 45.0 |
| 2023, Series B, 6.00%, tax exempt | 22.8 | 22.8 |
| 2025, 1993 Series, 7.625% | - | 20.0 |
| 2029, 1999 Senior Notes, 6.72% | 80.0 | 80.0 |
| 2015, 1985 Pollution Control Series A, adjustable rate presently 4.30%, tax exempt, next rate adjustment: 2004 | 10.0 | 10.0 |
| 2025, 1998 Pollution Control Series A, adjustable rate presently 4.75%, tax exempt, next rate adjustment: 2006 | 31.5 | 31.5 |
| 2024, 2000 Environmental Improvement Series A, fixed in April 2003 at 4.65%, tax exempt, weighted average for year: 3.69% | 22.5 | 22.5 |
| Total first mortgage bonds | 179.8 | 245.8 |
| Senior Unsecured Bonds to Third Parties: | | |
| 2020, 1998 Pollution Control Series B, fixed in April 2003 at 4.50%, tax exempt, weighted average for year: 4.16% | 4.6 | 4.6 |
| 2030, 1998 Pollution Control Series B, fixed in April 2003 at 5.00%, tax exempt, weighted average for year: 4.48% | 22.0 | 22.0 |
| 2030, 1998 Pollution Control Series C, adjustable rate presently 5.00%, tax exempt, next rate adjustment: 2006 | 22.2 | 22.2 |
| Total senior unsecured bonds | 48.8 | 48.8 |
| **Total SIGECO** | **228.6** | **294.6** |

| (In millions) | At December 31, 2003 | 2002 |
|---|---|---|
| **Indiana Gas** | | |
| Senior Unsecured Notes | | |
| 2003, Series F, 5.75% | - | 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%, $1.3 due annually in 2002 | - | 23.8 |
| 2025, Series E, 6.53% | 10.0 | 10.0 |
| 2027, Series E, 6.42% | 5.0 | 5.0 |
| 2027, Series E, 6.68% | 3.5 | 3.5 |
| 2027, Series F, 6.34% | 20.0 | 20.0 |
| 2028, Series F, 6.75% | - | 13.6 |
| 2028, Series F, 6.36% | 10.0 | 10.0 |
| 2028, Series F, 6.55% | 20.0 | 20.0 |
| 2029, Series G, 7.08% | 30.0 | 30.0 |
| 2030, Insured Quarterly, 7.45% | 49.9 | 49.9 |
| **Total Indiana Gas** | **214.9** | **267.3** |
| | | |
| **Total long-term debt outstanding** | **1,106.5** | **1,024.9** |
| Current maturities of long-term debt | (15.0) | (39.8) |
| Debt subject to tender | (13.5) | (26.6) |
| Unamortized debt premium & discount - net | (4.9) | (4.3) |
| Fair value of hedging arrangements | (0.3) | - |
| **Total long-term debt-net** | **$ 1,072.8** | **$ 954.2** |

VUHI 2003 Issuance

In July 2003, VUHI issued senior unsecured notes with an aggregate principal amount of $200 million in two $100 million tranches. The first tranche was 10-year notes due August 2013, with an interest rate of 5.25% priced at 99.746% to yield 5.28% to maturity (2013 Notes). The second tranche was 15-year notes due August 2018 with an interest rate of 5.75% priced at 99.177% to yield 5.80% to maturity (2018 Notes).

The notes have no sinking fund requirements, and interest payments are due semi-annually. The notes may be called by VUHI, 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 20 basis points for the 2013 Notes and 25 basis points for the 2018 Notes.

Shortly before these issues, VUHI entered into several treasury locks with a total notional amount of $150.0 million. Upon issuance of the debt, the treasury locks were settled resulting in the receipt of $5.7 million in cash, which was recorded as a regulatory liability pursuant to existing regulatory orders. The value received is being amortized as a reduction of interest expense over the life of the issues.

The net proceeds from the sale of the senior notes and settlement of related hedging arrangements approximated $203 million.

VUHI 2001 Issuance

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.

Shortly before these issues, the Company entered into several forward starting interest rate swaps with total notional amount of $200.0 million. Upon issuance of the debt, the treasury locks were settled resulting in the receipt of $0.9 million in cash, which was recorded as a regulatory liability pursuant to existing regulatory orders. The value received is being amortized as a reduction of interest expense over the life of the issues.

The net proceeds from the sale of the senior notes and settlement of the hedging arrangements totaled $344.0 million.

SIGECO and Indiana Gas Debt Call

During 2003, the Company called two first mortgage bonds outstanding at SIGECO and two senior unsecured notes outstanding at Indiana Gas. The first SIGECO bond had a principal amount of $45.0 million, an interest rate of 7.60%, was originally due in 2023, and was redeemed at 103.745% of its stated principal amount. The second SIGECO bond had a principal amount of $20.0 million, an interest rate of 7.625%, was originally due in 2025, and was redeemed at 103.763% of the stated principal amount.

The first Indiana Gas note had a remaining principal amount of $21.3 million, an interest rate of 9.375%, was originally due in 2021, and was redeemed at 105.525% of the stated principal amount. The second Indiana Gas note had a principal amount of $13.5 million, an interest rate of 6.75%, was originally due in 2028, and was redeemed at the principal amount.

Pursuant to regulatory authority, the premiums paid to retire the net carrying value of these notes totaling $3.6 million were deferred in *Regulatory assets*.

Other Financing Transactions

Other Company debt totaling $18.5 million in 2003, $6.5 million in 2002, and $7.6 million in 2001 was retired as scheduled.

At December 31, 2002, the Company had $26.6 million of adjustable rate senior unsecured bonds which could, at the election of the bondholder, be tendered to the Company when interest rates are reset. Such bonds were classified as *Long-term debt subject to tender*. During 2003, the Company re-marketed $4.6 million of the bonds through 2020 at a 4.5% fixed interest rate and remarketed $22.0 million of the bonds through 2030 at a 5.0% fixed interest rate. The bonds are now classified in *Long-term debt*.

Additionally, during 2003, the Company re-marketed $22.5 million of first mortgage bonds subject to interest rate exposure on a long term basis. The $22.5 million of mortgage bonds were remarketed through 2024 at a 4.65% fixed interest rate.

Long-Term Debt Sinking Fund Requirements & Maturities
The annual sinking fund requirement of SIGECO's first mortgage bonds is one percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. SIGECO intends to meet the 2004 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2004 is excluded from *Current liabilities* in the Consolidated Balance Sheets. At December 31, 2003, $502.0 million of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture.

Consolidated maturities and sinking fund requirements on long-term debt during the five years following 2003 (in millions) are $15.0 in 2004, $38.0 in 2005, zero in 2006, $24.0 in 2007, and zero in 2008.

Long-Term Debt Put & Call Provisions
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 which may be put to the Company during the years following 2003 (in millions) is $13.5 in 2004, $10.0 in 2005, $53.7 in 2006, $20.0 in 2007, zero in 2008, and $120.0 thereafter. Debt that may be put to the Company within one year is classified as *Long-term debt subject to tender* in current liabilities.

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, 2003, the Company was in compliance with all financial covenants.

Ratings Triggers
At December 31, 2003, $113.0 million of Vectren Capital's senior unsecured notes were subject to cross-default and ratings trigger provisions that would provide that the full balance outstanding is subject to prepayment if the ratings of Indiana Gas or SIGECO declined to BBB/Baa2. In addition, accrued interest and a make whole amount based on the discounted value of the remaining payments due on the notes would also become payable. The credit rating of Indiana Gas' senior unsecured debt and SIGECO's secured debt remains one level and two levels, respectively, above the ratings trigger.

Debt Guarantees
Vectren Corporation guarantees Vectren Capital's long-term and short-term debt, which totaled $113.0 million and $87.6 million, respectively, at December 31, 2003. VUHI's currently outstanding long-term and short-term debt is jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. VUHI's long-term and short-term debt outstanding at December 31, 2003, totaled $550.0 million and $184.4 million, respectively.

## 8. Cumulative Preferred Stock of 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 were 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, 2003, and 2002, there were 2,277 shares and 3,437 shares outstanding, respectively.

## 9. Common Shareholders' Equity

Equity Issuances

In March 2003, the Company filed a registration statement with the Securities and Exchange Commission with respect to a public offering of authorized but previously unissued shares of common stock as well as the senior unsecured notes of VUHI described above in Note 7. In August 2003, the registration became effective, and an agreement was reached to sell approximately 7.4 million shares to a group of underwriters. The net proceeds totaled $163.2 million.

In January 2001, the Company filed a registration statement with the Securities and Exchange Commission with respect to a public offering of authorized but previously unissued shares of common stock. In February 2001, the registration became effective, and an agreement was reached to sell approximately 6.3 million shares to a group of underwriters. The net proceeds totaled $129.4 million.

Authorized, Reserved Common and Preferred Shares

At December 31, 2003, and 2002, the Company was authorized to issue 480.0 million shares of common stock and 20.0 million shares of preferred stock. Of the authorized common shares, approximately 7.0 million shares at December 31, 2003, and 7.3 million shares at December 31, 2002, were reserved by the board of directors for issuance through the Company's equity-based compensation plans, benefit plans, and dividend reinvestment plan. At December 31, 2003, and 2002, there were 397.4 million and 404.8 million, respectively, of authorized shares of common stock and all authorized shares of preferred stock available for a variety of general corporate purposes, including future public offerings to raise additional capital and for facilitating acquisitions.

Shareholder Rights Agreement

The Company's board of directors has adopted a Shareholder Rights Agreement (Rights Agreement). As part of the Rights Agreement, the board of directors declared a dividend distribution of one right for each outstanding Vectren common share. Each right entitles the holder to purchase from Vectren one share of common stock at a price of $65.00 per share (subject to adjustment to prevent dilution). The rights become exercisable 10 days following a public announcement that a person or group of affiliated or associated persons (Vectren Acquiring Person) has acquired beneficial ownership of 15% or more of the outstanding Vectren common shares (or a 10% acquirer who is determined by the board of directors to be an adverse person), or 10 days following the announcement of an intention to make a tender offer or exchange offer the consummation of which would result in any person or group becoming a Vectren Acquiring Person. The Vectren Shareholder Rights Agreement expires October 21, 2009.

## 10. Earnings Per Share

Basic earnings per share is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share assumes the conversion of stock options into common shares and the lifting of restrictions on issued restricted shares using the treasury stock method to the extent the effect would be dilutive.

The following table illustrates the basic and dilutive earnings per share calculations for the three years ended December 31, 2003:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions, except per share data)* | 2003 | 2002 | 2001 |
| **Numerator:** | | | |
| Numerator for basic and diluted EPS - Net income | $ 111.2 | $ 114.0 | $ 52.7 |
| **Denominator:** | | | |
| Denominator for basic EPS - Weighted average common shares outstanding | 70.6 | 67.6 | 66.7 |
| Conversion of stock options and lifting of restrictions on issued restricted stock | 0.2 | 0.3 | 0.2 |
| Denominator for diluted EPS - Adjusted weighted average shares outstanding and assumed conversions outstanding | 70.8 | 67.9 | 66.9 |
| **Basic earnings per share** | **$ 1.58** | **$ 1.69** | **$ 0.79** |
| **Diluted earnings per share** | **$ 1.57** | **$ 1.68** | **$ 0.79** |

Options to purchase 530,663 shares of common stock for the year ended December 31, 2003, 87,963 shares of common stock for the year ended December 31, 2002, and 836,688 shares of common stock for the year ended December 31, 2001, were excluded in the computation of dilutive earnings per share because the options' exercise price was greater than the average market price of a share of common stock during the period. Exercise prices for options excluded from the computation ranged from $23.19 to $25.59 in 2003; $24.05 to $25.59 in 2002; and $22.54 to $24.05 in 2001.

## 11. Equity-Based Incentive Plans

The Company has various equity-based incentive plans to encourage employees and non-employee directors to remain with the Company and to more closely align their interest with those of the Company's shareholders.

Stock Option Plans

A summary of the status of the Company's stock option plans for the past three years follows:

| | Options | Wtd. Avg. Exercise Price |
|---|---|---|
| Outstanding at January 1, 2001 | 859,441 | $ 18.41 |
| Granted | 783,999 | 22.54 |
| Cancelled | (92,953) | 21.84 |
| Exercised | (122,709) | 16.05 |
| Outstanding at December 31, 2001 | 1,427,778 | 20.67 |
| Granted | 71,374 | 23.51 |
| Cancelled | (3,000) | 22.54 |
| Exercised | (146,890) | 14.51 |
| Outstanding at December 31, 2002 | 1,349,262 | 21.48 |
| Granted | 521,200 | 23.07 |
| Cancelled | (5,800) | 22.56 |
| Exercised | (61,766) | 17.30 |
| Outstanding at December 31, 2003 | **1,802,896** | **$ 22.08** |

In January 2004, 219,000 options to purchase shares of common stock at an exercise price of $24.74 were issued to management. The grant vests over three years.

Stock options granted to employees in 2003 become fully vested and exercisable at the end of three years. Stock options granted to employees in 2001 and 2002 become fully vested and exercisable at the end of five years. Stock options granted to non-employee directors in 2001, 2002, and 2003 become fully vested and exercisable at the end of one year. All options granted prior to 2001 are fully vested and exercisable. Options granted both before and after 2001 generally expire ten years from the date of grant.

The fair value of each option granted used to determine pro forma net income as disclosed in Note 2, is estimated as of the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in the years ended December 31, 2003, 2002, and 2001: risk-free rate of return of 4.26%, 3.80%, and 5.65%, respectively; expected option term of 8 years for all 3 years presented; expected volatility of 19.01%, 26.44% and 26.56%, respectively; and dividend yield of 4.50%, 4.65%, and 4.42%, respectively. The weighted average fair value of options granted in 2003, 2002, and 2001 were $3.31, $4.33 and $5.21, respectively.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2003:

| | Outstanding | | | Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | # of Options | Wtd. Avg. Remaining Contractual Life | Wtd. Avg. Exercise Price | # of Options | Wtd. Avg. Exercise Price |
| $13.82 - $17.44 | 80,350 | 1.7 | $ 15.86 | 80,350 | $ 15.86 |
| $19.83 - $20.26 | 304,484 | 4.8 | 20.11 | 304,484 | 20.11 |
| $22.37 - $22.57 | 887,399 | 7.6 | 22.54 | 412,799 | 22.53 |
| $23.19 - $25.59 | 530,663 | 8.4 | 23.38 | 127,216 | 23.87 |
| **Total** | **1,802,896** | **7.1** | **$ 22.08** | **924,849** | **$ 21.34** |

Stock options that were exercisable and those options' weighted average exercise prices were 692,288 and $20.37, respectively, at December 31, 2002, and 658,221 and $18.47, respectively, at December 31, 2001.

Other Plans

The Company maintains a performance-based restricted stock plan for its executives and a non-performance based restricted stock plan through which non-employee directors receive a portion of their director fees. A summary of outstanding restricted stock issued through these plans during the three years ended December 31, 2003, follows:

| | Restricted Stock |
|---|---|
| Outstanding at January 1, 2001 | 194,884 |
| Grants | 4,257 |
| Forfeitures | (19,726) |
| Vested | (1,302) |
| Outstanding at December 31, 2001 | 178,113 |
| Grants | 66,831 |
| Vested | (4,257) |
| Outstanding at December 31, 2002 | 240,687 |
| Grants | 120,228 |
| Forfeitures | (14,136) |
| Vested | (137,777) |
| **Outstanding at December 31, 2003** | **209,002** |

For the years ended December 31, 2003, 2002, and 2001, the weighted average fair value per share of restricted stock granted was $23.33, $23.10, and $22.54, respectively.

In January 2004, 133,500 options to purchase shares of common stock at an exercise price of $24.74 were issued to management. The grant vests over three years.

Executives and non-employee directors may defer certain portions of their salary, annual bonus, incentive compensation, and earned restricted stock into phantom stock units. Such units are vested when granted.

Compensation expense associated with the restricted stock and phantom stock plans for the years ended December 31, 2003, 2002, and 2001, was $3.6 million, $2.1 million, and $2.8 million, respectively.

## 12. Commitments & Contingencies

Commitments

Future minimum lease payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year during the five years following 2003 and thereafter (in millions) are $6.7 in 2004, $5.4 in 2005, $4.2 in 2006, $3.3 in 2007, $1.4 in 2008, and $0.6 thereafter. Total lease expense (in millions) was $7.2 in 2003, $7.3 in 2002, and $6.2 in 2001.

Firm purchase commitments for commodities total (in millions) $169.8 in 2004 and $34.5 in 2005. Firm purchase commitment for utility and nonutility plant total $117.8 million.

Other Guarantees

Vectren Corporation issues guarantees to third parties on behalf of its unconsolidated affiliates. Such guarantees allow those affiliates to execute transactions on more favorable terms than the affiliate could obtain without such a guarantee. Guarantees may include posted letters of credit, leasing guarantees, and performance guarantees. As of December 31, 2003, guarantees issued and outstanding on behalf of unconsolidated affiliates approximated $6 million. The Company has also issued a guarantee approximating $4 million related to the residual value of an operating lease that expires in 2006.

Vectren Corporation has accrued no liabilities for these guarantees as they relate to guarantees issued among related parties or were executed prior to the adoption of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). As more fully described in Note 19, FIN 45 was adopted prospectively and specifically excludes from its recognition and measurement provisions, guarantees issued among related parties.

Through December 31, 2003, the Company has not been called upon to satisfy any obligations pursuant to its guarantees. Liabilities accrued for, and activity related to, product warranties are not significant.

United States Securities and Exchange Commission (SEC) Informal Inquiry

As more fully described in the 2002 consolidated financial statements, the Company restated its annual consolidated financial statements for 2000 and 2001, and its 2002 quarterly results. The Company received an informal inquiry from the SEC with respect to this restatement. In response, the Company met with the SEC staff and provided information in response to their requests, with the most recent response provided on July 26, 2003.

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 13 regarding environmental matters.

## 13. 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 .141 lbs./MMBTU by May 31, 2004, (the compliance date). This is a 65% reduction in emission levels.

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 currently be the most effective method of reducing NOx emissions where high removal efficiencies are required.

The IURC has issued orders that approve:

- the Company's project to achieve environmental compliance by investing in clean coal technology;
- a total capital cost investment for this project up to $244 million (excluding AFUDC), subject to periodic review of the actual costs incurred;
- a mechanism whereby, prior to an electric base rate case, the Company may recover through a rider that is updated every six months, an eight percent return on its weighted capital costs for the project; and
- ongoing recovery of operating costs, including depreciation and purchased emission allowances through a rider mechanism, related to the clean coal technology once the facility is placed into service.

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 is consistent with amounts approved in the IURC's orders and is expected to be expended during the 2001-2006 period. Through December 31, 2003, $145.2 million has been expended. After the equipment is installed and operational, related annual operating expenses, including depreciation expense, are estimated to be between $24 million and $27 million. A portion of those expenses began in October 2003 when the Culley SCR became operational. The 8 percent return on capital investment approximates the return authorized in the Company's last electric rate case in 1995 and includes a return on equity.

The Company expects to achieve timely compliance as a result of the project. Construction of the first SCR at Culley was placed into service in October 2003, and construction of the Warrick 4 and Brown SCR's is proceeding on schedule. 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 was filed in the U.S. District Court for the Southern District of Indiana. The USEPA alleged 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 alleged that the modifications to the Culley Generating Station required SIGECO to begin complying with federal new source performance standards at its Culley Unit 3. The USEPA also issued an administrative notice of violation to SIGECO making the same allegations, but alleging that violations began in 1977.

On June 6, 2003, SIGECO, the Department of Justice (DOJ), and the USEPA announced an agreement that would resolve the lawsuit. The agreement was embodied in a consent decree filed in U.S. District Court for the Southern District of Indiana. The mandatory public comment period has expired, and no comments were received. The Court entered the consent decree on August 13, 2003.

Under the terms of the agreement, the DOJ and USEPA have agreed to drop all challenges of past maintenance and repair activities at the Culley coal-fired units. In reaching the agreement, SIGECO did not admit to any allegations in the government's complaint, and SIGECO continues to believe that it acted in accordance with applicable regulations and conducted only routine maintenance on the units. SIGECO has entered into this agreement to further its continued commitment to improve air quality and avoid the cost and uncertainties of litigation.

Under the agreement, SIGECO has committed to:
- either repower Culley Unit 1 (50 MW) with natural gas, which would significantly reduce air emissions from this unit, and equip it with SCR control technology for further reduction of nitrogen oxide, or cease operation of the unit by December 31, 2006;
- operate the existing SCR control technology recently installed on Culley Unit 3 (287 MW) year round at a lower emission rate than that currently required under the NOx SIP Call, resulting in further nitrogen oxide reductions;
- enhance the efficiency of the existing scrubber at Culley Units 2 and 3 for additional removal of sulphur dioxide emissions;
- install a baghouse for further particulate matter reductions at Culley Unit 3 by June 30, 2007;
- conduct a Sulphuric Acid Reduction Demonstration Project as an environmental mitigation project designed to demonstrate an advance in pollution control technology for the reduction of sulfate emissions; and
- pay a $600,000 civil penalty.

The Company anticipates that the settlement would result in total capital expenditures through 2007 in a range between $16 million and $28 million. Other than the $600,000 civil penalty, which was accrued in the second quarter of 2003, the implementation of the settlement, including these capital expenditures and related operating expenses, are expected to be recovered through rates.

*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 with the most recent correspondence provided on March 26, 2001.

<u>Manufactured Gas Plants</u>

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 (VRP) 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 VRP. 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 been initiated by the Company to confirm that the sites continue to pose no such risk.

On October 6, 2003, SIGECO filed applications to enter four of the manufactured gas plant sites in IDEM's VRP. The remaining site is currently being addressed in the VRP by another Indiana utility. SIGECO is adding its four sites into the renewal of the global Voluntary Remediation Agreement that Indiana Gas has in place with IDEM for its manufactured gas plant sites. The total costs, net of other PRP involvement and insurance recoveries, that may be incurred in connection with further investigation, and if necessary, remedial work at the four SIGECO sites cannot be determined at this time.

## 14. Rate & Regulatory Matters

Ohio Uncollectible Accounts Expense Tracker

On December 17, 2003, the PUCO approved a request by VEDO and several other regulated Ohio gas utilities to establish a mechanism to recover uncollectible accounts expense outside of base rates. The tariff mechanism establishes an automatic adjustment procedure to track and recover these costs instead of providing the recovery of the historic amount in base rates. Through this order, VEDO received authority to defer its 2003 uncollectible accounts expense to the extent it differs from the level included in base rates. The Company estimated the difference to approximate $4 million in excess of that included in base rates, and accordingly reversed previously established reserves and recorded a regulatory asset for the difference, totaling $3.0 million.

Gas Cost Recovery (GCR) Audit Proceedings

There is an Ohio requirement that Ohio gas utilities undergo a biannual audit of their gas acquisition practices in connection with the gas cost recovery (GCR) mechanism. In the case of VEDO, the two-year period began in November 2000, coincident with the Company's acquisition of the Ohio operations and commencement of service in Ohio. The audit provides the initial review of the portfolio administration arrangement between VEDO and ProLiance. The external auditor retained by the PUCO staff recently submitted an audit report wherein it recommended a disallowance of approximately $7 million of previously recovered gas costs. The Company believes a large portion of the third party auditor recommendations is without merit. There are two elements of the recommendations relating to the treatment of a pipeline refund and a penalty which VEDO does not oppose. A hearing has been held, and based on its audit report, the PUCO staff has recommended a $6.1 million disallowance. The Ohio Consumer Counselor has submitted testimony to support an $11.5 million disallowance. For this PUCO audit period, any disallowance relating to the Company's ProLiance arrangement will be shared by the Company's joint venture partner. Based on a review of the matters, the Company has reserved $1.1 million for its estimated share of a potential disallowance. The Company believes that these proceedings will not likely have a material effect on the Company's operating results or financial condition. However, the Company can provide no assurance as to the ultimate outcome of this proceeding.

Recovery of Purchased Power

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 2004, 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.

## 15. Derivatives & Other Financial Instruments

Accounting Policy for Derivatives

The Company executes derivative contracts in the normal course of operations while buying and selling commodities to be used in operations, optimizing its generation assets, and managing risk.

When an energy contract that is a derivative is designated and documented as a normal purchase or normal sale, it is exempted from mark-to-market accounting. Otherwise, energy contracts and financial contracts that are derivatives 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. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to SFAS 71. When hedge accounting is appropriate, the Company assesses and documents hedging relationships between the derivative contract and underlying risks as well as its risk management objectives and anticipated effectiveness. When the hedging relationship is highly effective, derivatives are designated as hedges. The market value of the effective portion of the hedge is marked to market in accumulated other comprehensive income for cash flow hedges or as an adjustment to the underlying's basis for fair value hedges. The ineffective portion of hedging arrangements is marked-to-market through earnings. The offset to contracts affected by SFAS 71 are marked-to-market as a regulatory asset or liability. Market value for all derivative contracts is determined using quoted market prices from independent sources. Following is a more detailed discussion of the Company's use of mark-to-market accounting in three primary areas: asset optimization, natural gas procurement, and interest rate management.

*Asset Optimization*
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. Substantially all of these contracts are integrated with portfolio requirements around power supply and delivery and are primarily short-term purchase and sale contracts that expose the Company to limited market risk. Contracts with counter-parties subject to master netting arrangements are presented net in the Consolidated Balance Sheets. Asset optimization contracts 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 *Electric utility revenues*.

Asset optimization contracts recorded at market value at December 31, 2003, totaled $2.4 million of *Prepayments & other current assets* and $2.8 million of *Accrued liabilities*, compared to $3.5 million of *Prepayments & other current assets* and $4.2 million of *Accrued liabilities* at December 31, 2002.

In July 2003, the EITF released EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3" (EITF 03-11). EITF 03-11 states that determining whether realized gains and losses on physically settled derivative contracts should be reported in the Statement of Income on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The EITF contains a presumption that net settled derivative contracts should be reported net in the Statement of Income. The Company adopted EITF 03-11 as required on October 1, 2003.

After considering the facts and circumstances relevant to the asset optimization portfolio, the Company believes presentation of these optimization activities on a net basis is appropriate and has reclassified purchase contracts and mark-to-market activity related to optimization activities from *Purchased electric energy* to *Electric utility revenues*. Prior year financial information has also been reclassified to conform to this net presentation. Following is information regarding asset optimization activities included in *Electric utility revenues* and *Fuel for electric generation* in the Statements of Income:

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| Activity related to: | | | |
| Sales contracts | $ 152.8 | $ 302.8 | $ 101.4 |
| Purchase contracts | (127.0) | (275.9) | (74.3) |
| Mark-to-market gains (losses) | 0.7 | (3.6) | 1.5 |
| Net asset optimization revenue | 26.5 | 23.3 | 28.6 |
| Fuel for electric generation | (8.2) | (10.6) | (9.5) |
| Asset optimization margin | $ 18.3 | $ 12.7 | $ 19.1 |

*Natural Gas Procurement Activity*
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. Although Vectren'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. The Company mitigates these risks by executing derivative contracts that manage the price of forecasted natural gas purchases. These contracts are subject to regulation which allows for reasonable and prudent hedging costs to be recovered through rates. When regulation is involved, SFAS 71

controls when the offset to mark-to-market accounting is recognized in earnings.

The Company's wholly owned gas retail operations also mitigate price risk associated with forecasted natural gas purchases by using derivatives. Such contracts are ordinarily designated and documented as cash flow hedges.

The market value of natural gas procurement derivative contracts at December 31, 2003, was not significant.

*Interest Rate Management*
The Company is exposed to interest rate risk associated with its borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on interest expense. The Company has used interest rate swaps and treasury locks to hedge forecasted debt issuances and other interest rate swaps to manage interest rate exposure. Hedging instruments are recorded at market value. Changes in market value, when effective, are recorded in *Accumulated other comprehensive income* for cash flow hedges, as an adjustment to the outstanding debt balance for fair value hedges, or as regulatory asset/liability when regulation is involved. Amounts are recorded to interest expense as settled.

As of December 31, 2003, interest rate swaps hedging the fair value of fixed-rate debt with a total notional amount of $55.5 million and a fair value liability of $0.3 million are outstanding. At December 31, 2003, approximately $6.2 million remains in *Regulatory liabilities* related to future interest payments from the 2003 and 2001 VUHI interest rate hedging activities. Of the existing regulatory liability, $0.6 million will be reclassified to earnings in 2004 and $0.3 million was reclassified to earnings during 2003.

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 a change in the derivative's market value be recognized currently in earnings unless specific hedge 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 or other comprehensive income, 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 asset optimization contracts and other commodity 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. The majority of this gain results from the Company's asset optimization operations. 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, | | | |
|---|---|---|---|---|
| | 2003 | | 2002 | |
| *(In millions)* | Carrying Amount | Est. Fair Value | Carrying Amount | Est. Fair Value |
| Long-term debt | $ 1,106.5 | $ 1,184.8 | $ 1,024.9 | $ 1,095.3 |
| Short-term borrowings & notes payable | 274.9 | 274.9 | 399.5 | 399.5 |

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.

Periodically, the Company tests its cost method investments and notes receivable for impairment which may require their fair value to be estimated. Because of the customized nature of these investments and lack of a readily available market, it is not practicable to estimate the fair value of these financial instruments at specific dates without considerable effort and costs. At December 31, 2003, and 2002, fair value for these financial instruments has not been estimated.

**16. Additional Operational & Balance Sheet Information**

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

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| AFUDC & capitalized interest | $ 5.9 | $ 5.7 | $ 6.3 |
| Interest income | 3.2 | 4.7 | 5.7 |
| Gains on sale of investments & assets | 7.5 | 1.8 | 2.9 |
| Leveraged lease investment income | 1.9 | 1.1 | 4.6 |
| Other income | 3.2 | 2.7 | 6.0 |
| Other expense | (8.7) | (4.5) | (8.8) |
| **Total other – net** | **$ 13.0** | **$ 11.5** | **$ 16.7** |

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

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Prepaid gas delivery service | $ 97.7 | $ 70.3 |
| Prepaid taxes | 20.1 | 4.8 |
| Other prepayments & current assets | 13.3 | 12.6 |
| **Total prepayments & other current assets** | **$ 131.1** | **$ 87.7** |

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

| | At December 31, | |
|---|---|---|
| *(In millions)* | 2003 | 2002 |
| Accrued taxes | $ 33.2 | $ 47.2 |
| Refunds to customers & customer deposits | 24.5 | 21.0 |
| Accrued interest | 16.5 | 14.0 |
| Deferred income taxes | 6.9 | 7.7 |
| Accrued salaries & other | 28.2 | 30.0 |
| **Total accrued liabilities** | **$ 109.3** | **$ 119.9** |

## 17. Segment Reporting

During 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 Company has reorganized and restated its operating segments from those segments reported in its 2002 financial statements to reflect this transfer. The reorganization did not affect the previous reporting of the Nonregulated group, but did affect all other previously reported segments. The Company now segregates its operations into three groups: 1) Utility Group, 2) Nonregulated Group, and 3) Corporate and Other Group.

The Utility Group is comprised of Vectren Utility Holdings, Inc.'s operations, which consist of the Company's regulated operations (the Gas Utility Services and Electric Utility Services operating segments), and other operations that provide information technology and other support services to those regulated operations. In total, there are three operating segments as defined by SFAS 131 "Disclosure About Segments of an Enterprise and Related Information" (SFAS 131). Gas Utility Services provides natural gas distribution and transportation services in nearly two-thirds of Indiana and to west central Ohio. Electric Utility Services provides electricity primarily to southwestern Indiana, and includes the Company's power generating and marketing operations. The Company collectively refers to its gas and electric operating segments as its regulated operations. For these regulated operations the Company uses after tax operating income as a measure of profitability, consistent with regulatory reporting requirements. The Company cross manages its regulated margin, other operating expenses, and capital expenditures as separated between Energy Delivery, which includes the gas and electric transmission and distribution functions, and Power Supply, which includes the power generating and marketing operations.

The Utility Group's other operations were formerly a component of the Corporate and Other Group. Other operations also contain other assets and operations that were previously allocated to the Gas Utility and Electric Utility Segments. The Company uses net income as the measure of the profitability for this segment.

The Nonregulated Group is comprised of one operating segment as defined by SFAS 131 that includes various subsidiaries and affiliates offering and investing in energy marketing and services, coal mining, utility infrastructure services, and broadband communications, among other energy-related opportunities.

The Corporate and Other Group is comprised of one operating segment as defined by SFAS 131 that includes unallocated corporate expenses such as branding and charitable contributions, among other activities, that benefit the Company's other operating segments.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| *(In millions)* | 2003 | 2002 | 2001 |
| **Revenues** | | | |
| Utility Group | | | |
| Gas Utility Services | $ 1,112.3 | $ 908.0 | $ 1,019.6 |
| Electric Utility Services | 335.7 | 328.6 | 308.5 |
| Other Operations | 26.5 | 22.4 | 29.1 |
| Eliminations | (25.7) | (22.1) | (28.9) |
| Total Utility Group | 1,448.8 | 1,236.9 | 1,328.3 |
| Nonregulated Group | 219.2 | 352.3 | 741.8 |
| Corporate & Other Group | 1.0 | 1.0 | 0.5 |
| Eliminations | (81.3) | (66.4) | (61.5) |
| Consolidated Revenues | $ 1,587.7 | $ 1,523.8 | $ 2,009.1 |

| (In millions) | Year Ended December 31, 2003 | 2002 | 2001 |
|---|---|---|---|
| **Profitability Measure** | | | |
| Utility Group: Regulated Operating Income | | | |
| (Operating Income Less Applicable Income Taxes) | | | |
| Gas Utility Services | $ 74.9 | $ 80.7 | $ 47.1 |
| Electric Utility Services | 63.8 | 73.2 | 56.5 |
| Total Regulated Operating Income | 138.7 | 153.9 | 103.6 |
| Regulated other income - net | 5.1 | 5.1 | 4.7 |
| Regulated interest expense & preferred dividends | (62.0) | (63.7) | (68.2) |
| Regulated cumulative effect change in accounting principle | - | - | 1.1 |
| Regulated Net Income | 81.8 | 95.3 | 41.2 |
| Other Operations Net Income | 3.8 | 1.8 | 3.6 |
| Utility Group Net Income | 85.6 | 97.1 | 44.8 |
| Nonregulated Group Net Income | 27.6 | 19.0 | 12.1 |
| Corporate & Other Group Net Loss | (2.0) | (2.1) | (4.2) |
| Consolidated Net Income | $ 111.2 | $ 114.0 | $ 52.7 |
| **Amounts Included in Profitability Measures** | | | |
| **Depreciation & Amortization** | | | |
| Utility Group | | | |
| Gas Utility Services | $ 61.1 | $ 56.8 | $ 58.5 |
| Electric Utility Services | 42.6 | 40.0 | 38.7 |
| Other Operations | 14.2 | 13.9 | 20.7 |
| Total Utility Group | 117.9 | 110.7 | 117.9 |
| Nonregulated Group | 10.5 | 8.6 | 5.9 |
| Corporate & Other Group | 0.3 | 0.3 | 0.3 |
| Consolidated Depreciation & Amortization | $ 128.7 | $ 119.6 | $ 124.1 |
| **Interest Expense** | | | |
| Utility Group | | | |
| Regulated Operations | $ 62.0 | $ 63.7 | $ 68.2 |
| Other Operations | 4.1 | 5.4 | 2.5 |
| Total Utility Group | 66.1 | 69.1 | 70.7 |
| Nonregulated Group | 9.7 | 9.1 | 12.5 |
| Corporate & Other Group | (0.2) | 0.3 | - |
| Consolidated Interest Expense | $ 75.6 | 78.5 | 83.2 |
| **Equity in Earnings of Unconsolidated Affiliates** | | | |
| Utility Group: Other Operations | $ (0.5) | $ (1.8) | $ (0.5) |
| Nonregulated Group | 12.7 | 10.9 | 13.9 |
| Consolidated Equity in Earnings of Unconsolidated Affiliates | $ 12.2 | $ 9.1 | $ 13.4 |

| (In millions) | Year Ended December 31, 2003 | 2002 | 2001 |
|---|---|---|---|
| **Income Taxes** | | | |
| Utility Group | | | |
| Gas Utility Services | $ 19.5 | $ 18.2 | $ (2.2) |
| Electric Utility Services | 29.8 | 27.5 | 21.1 |
| Other Operations | 2.3 | 1.1 | 2.4 |
| Total Utility Group | 51.6 | 46.8 | 21.3 |
| Nonregulated Group | (13.2) | (6.9) | (4.7) |
| Corporate & Other Group | (0.7) | (1.0) | (2.5) |
| Consolidated Income Taxes | $ 37.7 | $ 38.9 | $ 14.1 |

| (In millions) | At December 31, 2003 | 2002 |
|---|---|---|
| **Assets** | | |
| Utility Group | | |
| Gas Utility Services | $ 1,805.0 | $ 1,728.4 |
| Electric Utility Services | 974.6 | 891.6 |
| Other Operations | 162.4 | 171.6 |
| Eliminations | (16.9) | (11.2) |
| Total Utility Group | 2,925.1 | 2,780.4 |
| Nonregulated Group | 454.0 | 418.2 |
| Corporate & Other Group | 287.5 | 385.7 |
| Eliminations | (313.2) | (447.8) |
| Consolidated Assets | $ 3,353.4 | $ 3,136.5 |

| (In millions) | Year Ended December 31, 2003 | 2002 | 2001 |
|---|---|---|---|
| **Capital Expenditures** | | | |
| Utility Group | | | |
| Gas Utility Services | $ 95.0 | $ 63.0 | $ 77.8 |
| Electric Utility Services | 124.1 | 88.8 | 69.8 |
| Other Operations | 15.9 | 65.5 | 55.2 |
| Total Utility Group | 235.0 | 217.3 | 202.8 |
| Nonregulated Group | 13.2 | 28.0 | 35.0 |
| Corporate & Other Group | 2.3 | 2.2 | 17.2 |
| Transfers of Assets | (14.3) | (28.8) | (15.3) |
| Consolidated Capital Expenditures | $ 236.2 | $ 218.7 | $ 239.7 |
| | | | |
| **Investments in Equity Method Investees** | | | |
| Utility Group: Other Operations | $ - | $ 0.3 | $ 3.0 |
| Nonregulated Group | 16.6 | 12.2 | 19.7 |
| Consolidated Investments in Equity Method Investees | $ 16.6 | $ 12.5 | $ 22.7 |

## 18. Special Charges for 2001

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 $11.8 million were expensed in June 2001 as a direct result of the restructuring plan. Additional charges of $7.2 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 $19.0 million. These charges were comprised of $10.9 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 $4.1 million for consulting and other fees.

The $10.9 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: $10.3 million by the Gas Utility Services segment; $4.8 million by the Electric Utility Services segment; and $3.9 million by the Nonregulated segment.

Employee severance and related costs are associated with approximately 100 employees. Employee separation benefits include severance, healthcare, and outplacement services. During 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.

At the beginning of 2002, the remaining accrual related to the restructuring was $5.1 million. Of that amount, $2.1 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 restructuring accrual was $4.2 million ($2.2 million for severance and $2.0 million for lease costs). During 2003, $1.0 million was paid for severance, and the accrual for lease costs did not substantially change. At December 31, 2003, the remaining restructuring accrual was $3.2 million ($1.2 million for severance and $2.0 million for lease costs). The restructuring accrual is included in *Accrued liabilities*.

Merger & Integration Costs

Merger and integration costs incurred for the year ended December 31, 2001, totaled $2.8 million. Those costs related 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 approximately $9.6 million ($6.0 million after tax) for the year ended December 31, 2001. Merger and integration activities resulting from the 2000 merger were completed in 2001.

## 19. Impact of Recently Issued Accounting Guidance

SFAS 132 (Revised 2003)

In December 2003, FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS 132), to improve financial statement disclosures for defined benefit plans. The change replaces existing FASB disclosure requirements for pensions and postretirement plans. The guidance is effective for fiscal years ending after December 15, 2003. The adoption did not impact the Company's results of operations or financial condition. The incremental disclosure requirements are included in these financial statements in Note 6. In addition to expanded annual disclosures, SFAS 132, as revised, requires the reporting of various elements of pension and other postretirement benefit costs on a quarterly basis.

SFAS 149

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends and clarifies the accounting guidance on (1) derivative instruments (including certain derivative instruments embedded in other contracts) and (2) hedging activities that fall within the scope of FASB Statement No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities." SFAS 149 amends SFAS 133 to reflect decisions that were made (1) as part of the process undertaken by the Derivatives Implementation Group (DIG), which necessitated amending SFAS 133, (2) in connection with other projects dealing with financial instruments, and (3) regarding implementation issues related to the application of the definition of a derivative. SFAS 149 also amends certain other existing pronouncements which will result in more consistent reporting of contracts that are derivatives in their entirety or that contain embedded derivatives that warrant separate accounting. SFAS 149 is effective (1) for contracts entered into or modified after June 30, 2003, with certain exceptions and (2) for hedging relationships designated after June 30. The guidance is to be applied prospectively. The adoption did not have a material effect on the Company's results of operations or financial condition.

SFAS 150

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" (SFAS 150). SFAS 150 requires issuers to classify as liabilities the following three types of freestanding financial instruments: mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets, and certain obligations to issue a variable number of shares. SFAS 150 was effective immediately for financial instruments entered into or modified after May 31, 2003; otherwise, the standard was effective for all other financial instruments at the beginning of the Company's third quarter of 2003. In October 2003, the FASB issued further guidance regarding mandatorily redeemable stock which is effective January 1, 2004, for the Company. The Company has approximately $200,000 of outstanding preferred stock of a subsidiary that is redeemable on terms outside the Company's control. However, the preferred stock is not redeemable on a specified or determinable date or upon an event that is certain to occur. The adoption of SFAS 150 on January 1, 2004, did not affect the Company's results of operations or financial condition.

FASB Interpretation (FIN) 45

In November 2002, the FASB issued 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 fair value of the obligations it has undertaken. The initial recognition and measurement provisions were applicable on a prospective basis to guarantees issued or modified after December 31, 2002. Since that date, the adoption has not had a material effect on the Company's results of operations or financial condition. The incremental disclosure requirements are included in these financial statements in Note 12.

FIN 46/46-R (Revised in December 2003)

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 (VIE) and significantly changes the consolidation requirements for those entities. FIN 46 is intended to achieve more consistent application of consolidation policies related to VIE's and thus improves comparability between enterprises engaged in similar activities when those activities are conducted through VIE's. In December 2003, the FASB completed its deliberations of proposed modifications to FIN 46 and decided to codify both the proposed modifications and other decisions previously issued through certain FASB Staff Positions into one document that was issued as a revision to the original Interpretation (FIN 46-R). FIN 46-R currently applies to VIE's created after January 31, 2003, and to VIE's in which an enterprise obtains an interest after that date. For entities created prior to January 31, 2003, FIN 46 is to be adopted no later than the end of the first interim or annual reporting period ending after March 15, 2004.

The Company has neither created nor obtained an interest in a VIE since January 31, 2003. Certain other entities that the Company was involved with prior to that date, including limited partnership investments that operate affordable housing projects, are still being evaluated to determine if the entity is a VIE and, if so, if Vectren is the primary beneficiary. If these entities are determined to be VIE's and Vectren is determined to be the primary beneficiary, the effect to the Company's financial statements would not be material.

Staff Accounting Bulletin No. 104
In December 2003, the SEC published Staff Accounting Bulletin (SAB) No. 104, "Revenue Recognition". This SAB updates portions of the SEC staff's interpretive guidance provided in SAB 101 and included in Topic 13 of the Codification of Staff Accounting Bulletins. SAB 104 deletes interpretative material no longer necessary and conforms the interpretive material retained because of pronouncements issued by the FASB's EITF on various revenue recognition topics, including EITF 00-21, "Revenue Arrangements with Multiple Deliverables." The Company's adoption of the standard did not have an impact on its revenue recognition policies.

**20. Quarterly Financial Data (Unaudited)**

Quarterly operating revenues presented below have been adjusted to reflect the adoption of EITF 03-11. See Note 15 to the consolidated financial statements for further information on the adoption of EITF 03-11. 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 2003 and 2002 follows:

| *(In millions, except per share amounts)* | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| **2003** | | | | |
| **Results of Operations:** | | | | |
| Operating revenues | $ 626.7 | $ 268.4 | $ 240.3 | $ 452.3 |
| Operating income | 94.7 | 17.5 | 18.2 | 69.0 |
| Net income | 55.7 | 4.1 | 7.3 | 44.1 |
| **Per Share Data:** | | | | |
| Earnings per share: | | | | |
| Basic | $ 0.82 | $ 0.06 | $ 0.10 | $ 0.59 |
| Diluted | 0.82 | 0.06 | 0.10 | 0.58 |
| **2002** | | | | |
| **Results of Operations:** | | | | |
| Operating revenues | $ 574.2 | $ 298.0 | $ 216.3 | $ 435.3 |
| Operating income | 82.9 | 25.6 | 31.5 | 71.3 |
| Net income | 45.6 | 12.5 | 13.5 | 42.4 |
| **Per Share Data:** | | | | |
| Earnings per share: | | | | |
| Basic | $ 0.68 | $ 0.18 | $ 0.20 | $ 0.63 |
| Diluted | 0.67 | 0.18 | 0.20 | $ 0.62 |

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

None.

## ITEM 9a. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Controls and Procedures

As of December 31, 2003, 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 at providing reasonable assurance that 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) is brought to their attention on a timely basis.

Disclosure controls and procedures, as defined by the Exchange Act in Rules 13a-15(e) and 15d-15(e), 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 Over Financial Reporting

During the quarter ended December 31, 2003, there have been no significant changes to the Company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Internal control over financial reporting is defined by the SEC in *Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports*. The final rule defines internal control over financial reporting as a process designed by, or under the supervision of, the registrant's principal executive and principal financial officers, or persons performing similar functions, and effected by the registrant's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the registrant, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the registrant are being made only in accordance with authorizations of management and directors of the registrant, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the registrant's assets that could have a material effect on the financial statements.

# PART III

## ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Except with respect to information regarding the executive officers of the Registrant, the information required by Part III, Item 10 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year. The information with respect to the executive officers of the Registrant is included below:

**Niel C. Ellerbrook,** age 55, has been a director of Indiana Energy, Inc. ("Indiana Energy"), a predecessor to the Company, or the Company since 1991. Mr. Ellerbrook has been Chairman of the Board and Chief Executive Officer of the Company since March 31, 2000, and President of the Company since May 1, 2003. Mr. Ellerbrook has also served as a Chairman and Chief Executive Officer of Indiana Gas, SIGECO, and VUHI since March 31, 2000, and of VEDO since November 1, 2000. Prior to March 31, 2000, and since June 1999, Mr. Ellerbrook served as President and Chief Executive Officer of Indiana Energy. Prior to that time, and since October 1997, Mr. Ellerbrook served as President and Chief Operating Officer of Indiana Energy. From January through October 1997, Mr. Ellerbrook served as Executive Vice President, Treasurer and Chief Financial Officer of Indiana Energy, and prior to that time and since 1986, Vice President, Treasurer, and Chief Financial Officer. Mr. Ellerbrook is also the Chair and a director of Vectren Capital and Vectren Enterprises and President, Chair and a director of Vectren Foundation. He is also a director of Old National Bancorp.

**Jerome A. Benkert, Jr.**, age 45, has served as Executive Vice President and Chief Financial Officer of the Company since March 31, 2000, and as Treasurer of the Company from October 2001 to March 31, 2002. Mr. Benkert has also served as a director and Executive Vice President and Chief Financial Officer of Indiana Gas, SIGECO and VUHI since March 31, 2000, and of VEDO since November 1, 2000. Prior to March 31, 2000, and since October 1, 1997, he was Executive Vice President and Chief Operating Officer of Indiana Energy's administrative services company. Mr. Benkert has served as Controller and Vice President of Indiana Gas. Mr. Benkert served as Assistant Treasurer for Indiana Gas from January 1, 1991, to October 1, 1993. Mr. Benkert served as Chief Accountant, Secretary/Treasurer and was a member of the board of directors of Richmond Gas Corporation from February 1, 1986, to January 1, 1991. Mr. Benkert is also a director and President of Vectren Capital and a director of Vectren Enterprises and Vectren Foundation. He is also a director of Fifth Third Bank, Indiana (Southern), Deaconess Hospital of Evansville, Indiana, and ProLiance.

**Carl L. Chapman**, age 48, was elected Executive Vice President of the Company and President of Vectren Enterprises, Inc. on March 31, 2000. Prior to March 31, 2000, and since 1999, Mr. Chapman served as Executive Vice President and Chief Financial Officer of Indiana Energy. From October 1, 1997, to June, 2002, Mr. Chapman served as President of IGC Energy, Inc., which has been renamed Vectren Energy Marketing and Services, Inc. ("VEMS"). Mr. Chapman served as President of ProLiance Energy, LLC ("ProLiance"), a gas supply and energy marketing joint venture partially owned by VEMS, an indirect, wholly owned subsidiary of the Company, from March 15, 1996, until April 30, 1998. Currently, Mr. Chapman is the Chair and a director of ProLiance. From 1995 until March 15, 1996, he was Senior Vice President of Corporate Development for Indiana Gas. Prior to 1995 and since 1987, he was Vice President of Planning for Indiana Gas. Mr. Chapman is also a director and President of Vectren Enterprises and a director of Vectren Capital and Vectren Foundation.

**Ronald E. Christian**, age 45, was elected Executive Vice President, General Counsel and Secretary of the Company on May 1, 2003. Prior to May 1, 2003, and since March 31, 2000, Mr. Christian served as Senior Vice President, General Counsel and Secretary of the Company. Mr. Christian has also served as a director and Executive Vice President and Secretary of Indiana Gas, SIGECO, and VUHI, and VEDO since May 1, 2003. Prior to March 31, 2000, and since 1999, he was Vice President and General Counsel of Indiana Energy, Inc. From July of 1998 to July of 1999, Mr. Christian served as Vice President, General Counsel and Secretary of Michigan Consolidated Gas Company. Mr. Christian served as General Counsel and Secretary of Indiana Energy, Inc. from 1993 to 1998. Prior to 1993 and since 1988, Mr. Christian was employed as counsel for the Company. Mr. Christian is also a director and Executive Vice President and General Counsel, and Secretary of Vectren Enterprises and a director and Vice President, Secretary and Assistant Treasurer of Vectren Capital and Vectren Foundation. Mr. Christian is a director of ProLiance.

**William S. Doty,** age 52, was elected Executive Vice President of Utility Operations on May 1, 2003. Prior to May 1, 2003, and since April 2001, Mr. Doty served as Senior Vice President-Energy Delivery of the Company. Mr. Doty has also served as a director and President of Indiana Gas, SIGECO, and VUHI and as a director and Executive Vice President of VEDO since May 1, 2003. Mr. Doty served as Senior Vice President of Customer Relationship Management of the Company from January 2001 to April 2001. From January 1999 to January 2001, Mr. Doty was Vice President of Energy Delivery for SIGECO and previous to January 1999, he was Director of Gas Operations for SIGECO.

**Richard G. Lynch**, age 52, was elected Senior Vice President-Human Resources and Administration of the Company on March 31, 2000. Mr. Lynch has also served as Senior Vice President-Human Resources and Administration of Indiana Gas, SIGECO, VUHI, and Vectren Enterprises since March 31, 2000, and of VEDO since November 1, 2000. Mr. Lynch served as 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.

The Company's Corporate Governance Guidelines, its charters for each of its Audit, Compensation and Nominating and Corporate Governance Committees, and its Code of Ethics covering the Company's directors, officers and employees are available on the Company's website, *www.vectren.com*, and a copy will be mailed upon request to Investor Relations, Attention: Steve Schein, 20 N.W. Fourth Street, Evansville, Indiana 47708. The Company intends to disclose any amendments to the Code of Ethics or waivers of the Code of Ethics on behalf of the Company's directors or officers including, but not limited to, the principal executive officer, principal financial officer, principal accounting officer or controller and persons performing similar functions on the Company's website at the Internet address set forth above promptly following the date of such amendment or waiver and such information will also be available by mail upon request to Investor Relations, Attention: Steve Schein, 20 N.W. Fourth Street, Evansville, Indiana 47708.

## ITEM 11. EXECUTIVE COMPENSATION

Information required by Part III, Item 11 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

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

Except with respect to equity compensation plan information of the Registrant, the information required by Part III, Item 12 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

The information with respect to common shares issuable under equity compensation plans as of December 31, 2003, with respect to the Registrant 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] | 2,021,896 [2] | $ 22.37 | 2,901,780 [3] |
| Equity compensation plans not approved by security holders | - | - | - |
| Total | 2,021,896 | $ 22.37 | 2,901,780 |

[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 of 219,000 options approved by the board of directors' Compensation Committee, effective January 1, 2004.

[3] Includes shares available for issuance under the Vectren Corporation At-Risk Compensation Plan (2,218,964), of which up to 800,000 shares may be issued in restricted stock, 1994 SIGCORP Stock Option Plan (374,249), Vectren Corporation Executive Restricted Stock Plan (273,338), and Vectren Corporation Directors Restricted Stock Plan (48,229). Shares available for issuance under the At Risk Plan have been reduced by the issuance of 133,500 restricted shares approved by the board of directors' Compensation Committee, effective January 1, 2004.

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

Information required by Part III, Item 13 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

## ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by Part III, Item 14 of this Form 10-K is incorporated by reference herein, and made part of this Form 10-K, from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, within 120 days after the end of the fiscal year.

## PART IV

## 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.

Supplemental Schedules

For the years ended December 31, 2003, 2002, and 2001, the Company's Schedule II -- Valuation and Qualifying Accounts Consolidated Financial Statement Schedules is presented on page 94. 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 attached to this filing filed electronically with the SEC are listed on page 95.
Exhibits for the Company are listed in the Index to Exhibits beginning on page 96.

### Reports On Form 8-K During The Last Calendar Quarter

On October 22, 2003, Vectren Corporation filed a Current Report on Form 8-K with respect to the release of financial information to the investment community regarding the Company's results of operations, financial position and cash flows for the three, nine, and twelve month periods ended September 30, 2003. The financial information was released to the public through this filing.

Item 7. Exhibits
99-1 – Press Release - Vectren Corporation Reports Third Quarter 2003 Results
99-2 – Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995
Item 12. Results of Operations and Financial Condition

On December 11, 2003, Vectren Corporation filed a Current Report on Form 8-K with respect to an analyst meeting where a discussion of the Company's current financial and operating results and plans for the future will occur.

Item 9. Regulation FD Disclosure
Index to Exhibits
99-1 – Press Release - Vectren Corporation Provides 2004 Earnings Guidance
99- 2 – Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

**SCHEDULE II**

Vectren Corporation and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

| Column A | Column B | Column C | | Column D | Column E |
|---|---|---|---|---|---|
| | | Additions | | | |
| Description | Balance at Beginning Of Year | Charged to Expenses | Charged to Other Accounts | Deductions from Reserves, Net | Balance at End of Year |
| *(In millions)* | | | | | |
| **VALUATION AND QUALIFYING ACCOUNTS: AS RESTATED** | | | | | |
| Year 2003 – Accumulated provision for uncollectible accounts | $ 5.5 | $ 12.8 | $ - | $ 15.1 | $ 3.2 |
| Year 2002 – Accumulated provision for uncollectible accounts | $ 5.3 | $ 11.7 | $ - | $ 11.5 | $ 5.5 |
| Year 2001 – Accumulated provision for uncollectible accounts | $ 5.1 | $ 17.3 | $ - | $ 17.1 | $ 5.3 |
| **OTHER RESERVES:** | | | | | |
| Year 2003 – Reserve for restructuring costs | $ 4.2 | $ - | $ - | $ 1.0 | $ 3.2 |
| Year 2002 – Reserve for restructuring costs | $ 5.1 | $ - | $ - | $ 0.9 | $ 4.2 |
| Year 2001 – Reserve for restructuring costs | $ - | $ 11.9 | $ - | $ 6.8 | $ 5.1 |
| 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 |

**Vectren Corporation**
**2003 Form 10-K**
**Attached Exhibits**

The following Exhibits are included in this Annual Report on Form 10-K.

| Exhibit Number | Document |
|---|---|
| 31.1 | Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

The following Exhibits were filed electronically with the SEC with this filing. See Page 96 of this Annual Report on Form 10-K for a complete list of exhibits.

| Exhibit Number | Document |
|---|---|
| 10.15 | Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC, effective August 30, 2003. |
| 10.16 | Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, effective September 1, 2002. |
| 10.18 | Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., dated December 17, 1997 and effective January 1, 1998. |
| 10.19 | Amendment 1, effective January 1, 2003, to Coal Supply Agreement between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc originally dated December 17, 1997. |
| 10.20 | Coal Supply Agreement for Generating Stations at Yankeetown, Warrick County, Indiana, and West Franklin, Posey County, Indiana between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., dated January 19, 2000. |
| 10.21 | Amendment 1, effective January 1, 2004, to Coal Supply Agreement between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc originally dated January 19, 2000. |
| 10.22 | Coal Supply Agreement for Warrick Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc. dated January 1, 2004. |
| 10.23 | Coal Supply Agreement for Warrick Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc. dated January 1, 2004. |
| 21.1 | List of Company's Significant Subsidiaries |
| 23.1 | Consent of Independent Public Accountants |

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 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.)

3.2 Amended and Restated Code of By-Laws of Vectren Corporation as of October 29, 2003. (Filed and designated in Quarterly Report on Form 10-Q filed November 13, 2003, File No. 1-15467, as Exhibit 3.1.)

3.3 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.)

**4. Instruments Defining the Rights Of Security Holders, Including Indentures**

4.1 Indenture dated October 19, 2001, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.1); First Supplemental Indenture, dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.2); Second Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 29, 2001, File No. 1-16739, as Exhibit 4.1); Third Supplemental Indenture, among Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated July 24, 2003, File No. 1-16739, as Exhibit 4.1) .

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 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.) First Amendment, effective April 16, 1997 (Filed and designated in Form 10-K for the fiscal year 1997, File No. 1-3553, as Exhibit 10.29.).

10.2 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.)

10.3 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.)

10.4 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.)

10.5 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.) First Amendment, 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.).

10.6 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.) First Amendment, 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.) Second Amendment, 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.) Third Amendment, 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.)

10.7 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.)

10.8 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.)

10.9 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.)

10.10 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.)

10.11 Vectren Corporation Employment Agreement between Vectren Corporation and Carl L. Chapman 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 99.4.)

10.12 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.)

10.13 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.)

10.14 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.)

10.15 Gas Sales and Portfolio Administration Agreement between Indiana Gas Company, Inc. and ProLiance Energy, LLC, effective August 30, 2003. (Filed herewith)

10.16 Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, effective September 1, 2002. (Filed herewith.)

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

10.18 Coal Supply Agreement for F.B. Culley Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., dated December 17, 1997 and effective January 1, 1998. (Filed herewith.)

10.19 Amendment 1, effective January 1, 2003, to Coal Supply Agreement between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc originally dated December 17, 1997. (Filed herewith.)

10.20 Coal Supply Agreement for Generating Stations at Yankeetown, Warrick County, Indiana, and West Franklin, Posey County, Indiana between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc., dated January 19, 2000. (Filed herewith.)

10.21 Amendment 1, effective January 1, 2004, to Coal Supply Agreement between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc originally dated January 19, 2000. (Filed herewith.)

10.22 Coal Supply Agreement for Warrick Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc. dated October 1, 2003. (Filed herewith.)

10.23 Coal Supply Agreement for Warrick Generating Station between Southern Indiana Gas and Electric Company and Vectren Fuels, Inc. dated January 1, 2004. (Filed herewith.)

10.24 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.)

**21. Subsidiaries of the Company**
The list of the Company's significant subsidiaries is attached hereto as Exhibit 21.1.

**23. Consents of Experts and Counsel**
The consent of Deloitte & Touche LLP is attached hereto as Exhibit 23.1.

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

Chief Financial Officer Certification Pursuant to Section 302 Of The Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 31.2

**32. Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
Certification Pursuant To Section 906 of the Sarbanes-Oxley Act Of 2002 is attached hereto as Exhibit 32.1

SIGNATURES

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

VECTREN CORPORATION

Dated February 25, 2004

/s/ Niel C. Ellerbrook
Niel C. Ellerbrook,
Chairman, President, Chief Executive Officer, and Director

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

| **Signature** | **Title** | **Date** |
|---|---|---|
| /s/ Niel C. Ellerbrook<br>Niel C. Ellerbrook | Chairman, President, Chief Executive Officer, & Director (Principal Executive Officer) | February 25, 2004 |
| /s/ Jerome A. Benkert, Jr.<br>Jerome A. Benkert, Jr. | Executive Vice President & Chief Financial Officer (Principal Financial Officer) | February 25, 2004 |
| /s/ M. Susan Hardwick<br>M. Susan Hardwick | Vice President & Controller (Principal Accounting Officer) | February 25, 2004 |
| /s/ John M. Dunn<br>John M. Dunn | Director | February 25, 2004 |
| /s/ John D. Engelbrecht<br>John D. Engelbrecht | Director | February 25, 2004 |
| /s/ Lawrence A. Ferger<br>Lawrence A. Ferger | Director | February 25, 2004 |
| /s/ Anton H. George<br>Anton H. George | Director | February 25, 2004 |

| | | |
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| /s/ Robert L. Koch II<br>Robert L. Koch II | Director | February 25, 2004 |
| /s/ William G. Mays<br>William G. Mays | Director | February 25, 2004 |
| /s/ J. Timothy McGinley<br>J. Timothy McGinley | Director | February 25, 2004 |
| /s/ Richard P. Rechter<br>Richard P. Rechter | Director | February 25, 2004 |
| /s/ Ronald G. Reherman<br>Ronald G. Reherman | Director | February 25, 2004 |
| /s/ R. Daniel Sadlier<br>R. Daniel Sadlier | Director | February 25, 2004 |
| /s/ Richard W. Shymanski<br>Richard W. Shymanski | Director | February 25, 2004 |
| /s/ Jean L.Wojtowicz<br>Jean L.Wojtowicz | Director | February 25, 2004 |

**Exhibit 31.1**

## CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

## CHIEF EXECUTIVE OFFICER CERTIFICATION

I, Niel C. Ellerbrook, certify that:

1. I have reviewed this Annual Report on Form 10-K of Vectren Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2004

/s/ Niel C. Ellerbrook
Niel C. Ellerbrook
Chairman, President, & Chief
Executive Officer

**Exhibit 31.2**

## CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

## CHIEF FINANCIAL OFFICER CERTIFICATION

I, Jerome A. Benkert, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K of Vectren Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2004

/s/ Jerome A. Benkert, Jr.
Jerome A. Benkert, Jr.
Executive Vice President & Chief
Financial Officer

**Exhibit 32.1**

**CERTIFICATION PURSUANT TO**
**SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

CERTIFICATION

By signing below, each of the undersigned officers hereby certifies pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his or her knowledge, (i) this Annual Report on Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in this report fairly presents, in all material respects, the financial condition and results of operations of Vectren Corporation.

Signed this 25th day of February, 2004.

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|---|---|
| /s/ Jerome A. Benkert, Jr. | /s/ Niel C. Ellerbrook |
| (Signature of Authorized Officer) | (Signature of Authorized Officer) |
| Jerome A. Benkert, Jr. | Niel C. Ellerbrook |
| (Typed Name) | (Typed Name) |
| Executive Vice President & Chief Financial Officer | Chairman, President & Chief Executive Officer |
| (Title) | (Title) |