Large Filing Separator Sheet

Case Number: 08-709-EL-AIR
08-710-EL-ATA
08-711-EL-AAM

Date Filed: 7/25/2008

Section: 3 of 3

Number of Pages: 135

Description of Document: Application
Volume 8
Supplemental Information
(C) (5)

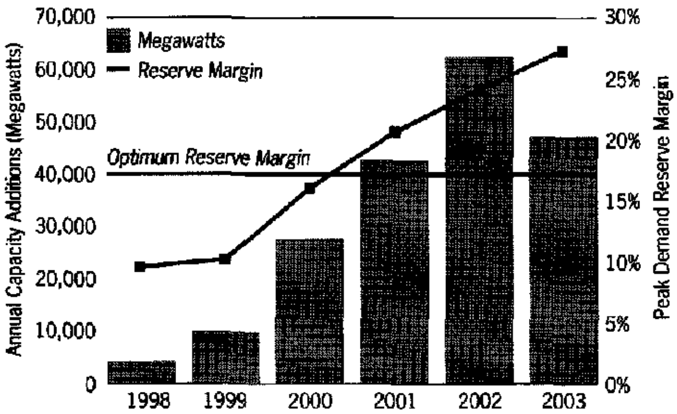
Dear Fellow Shareholder,

As I sit down to write this letter, I start from a perspective I know we share. Like many of you, I am a long-term holder of Duke Energy stock, having acquired much of it over the years prior to the merger of PanEnergy and Duke Power. When I left the company in 1998 to become CEO of Australian based BHP Ltd., Duke Energy was prospering, the stock price was buoyant and the industry seemed to be entering an era of unprecedented growth and prosperity. Since returning to the U.S. and rejoining...

THE ENVIRONMENT WE ARE IN

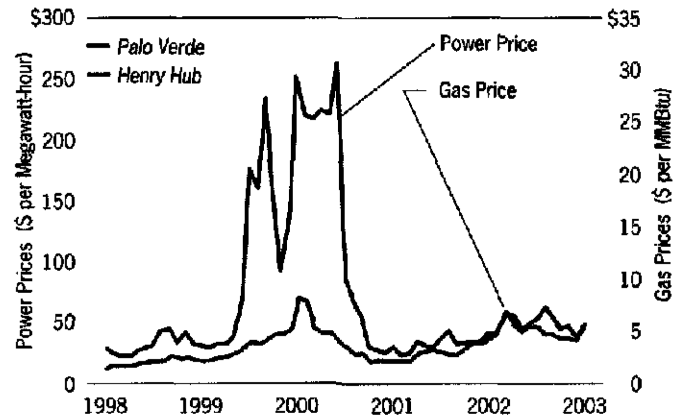
The energy landscape has changed drastically in the past five years. New generating capacity has outpaced demand growth, causing a decline in power prices while natural gas prices rose. Meanwhile, restructuring largely stalled, slowing the transition to a more competitive marketplace. Here are a few indicators of how our industry has changed since 1998.

U.S Capacity Additions/Reserve Margins



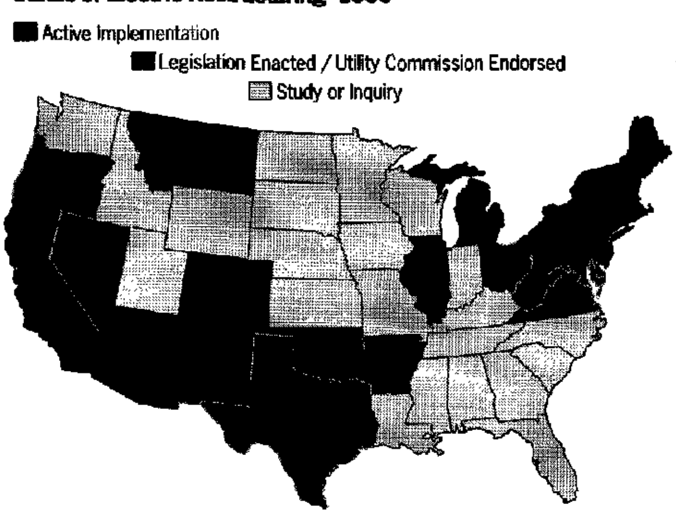
The industry continued to add capacity beyond what was needed for adequate reserve margins. The optimum U.S. reserve for electricity is approximately 17 percent higher than peak demand to handle weather extremes, power outages and other conditions.

Power and Gas Prices
(Average Monthly)

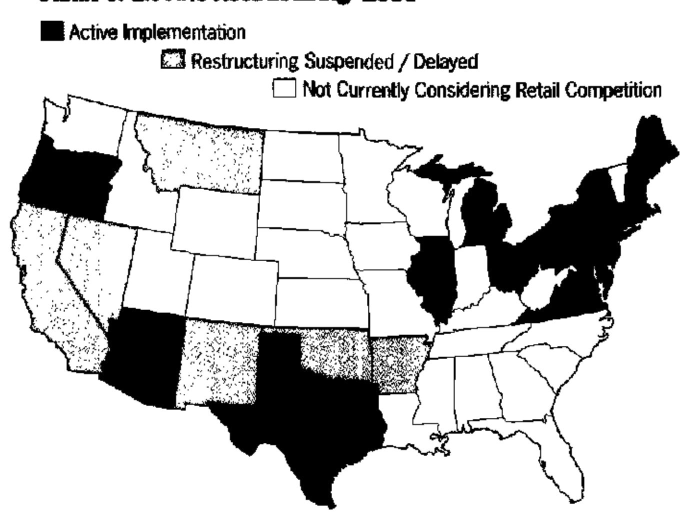


Normal gas and power price relationships gave way to extreme volatility from the late 1990s into mid-2001. When power prices plummeted, so did the profit margins from gas-fired electric generation. (Prices shown are as reported at the Henry Hub and Palo Verde trading centers.)

Status of Electric Restructuring 1999



Status of Electric Restructuring 2003



The push for electric restructuring has slowed dramatically. While implementation is underway in some states with varying results, most are not currently considering retail competition, and several have suspended deregulation or delayed their plans.

... Duke, I have been amazed at how much the landscape has changed in just five short years. The thriving industry I left is like a bombed-out village. Parts of it remain and are recognizable, but other parts are missing or damaged beyond recognition. And some of the damage was self-inflicted.

The State of the Industry

In 2000, the combined market capitalization of the ten largest integrated energy firms exceeded $230 billion. By the end of 2003, their combined market cap had dropped by more than $100 billion. Today, half of that group would not even make the ten-largest list by market capitalization.

Of the companies that comprised the Interstate Natural Gas Association of America and the Edison Electric Institute at year-end 1998, more than a quarter have merged or otherwise disappeared. Several have filed for bankruptcy and still more have had their debt lowered to below investment grade. Roughly one in four has changed names, and more than 50 percent have changed their CEOs. The new breed of independent power producers has fared even worse, while many involved in energy trading have been discredited.

Changes to market dynamics and the regulatory climate have been no less dramatic. The dream of an integrated gas and power generation industry serving free and open markets with a balance of hard assets and trading has turned into a nightmare. Overly aggressive estimates of demand led power generators to add enormous chunks of new capacity just as the cycle was peaking. Traders began to confuse a bull market with brains and became the new "masters of the universe." Many company managements aspired to be increasingly clever rather than good, and spoke of "virtual" companies without assets. The price of natural gas was all over the map, but it looked tame compared to volatility in the electric markets. By the end of 2003, liquidity in many markets had all but disappeared.

The landscape was also reshaped by regulatory and legislative action – and inaction. The rush toward deregulation halted mid-stream, leaving the industry in limbo with a mixture of state and federal laws and regulations that often conflicted and contributed to the problems. Recent focus has been to put constraints on the industry to prevent a repeat of past excesses. Unfortunately, some of these controls destroy or eliminate many of the benefits originally envisioned for an integrated energy industry.

Of course, it's not just the energy industry that has changed over the last five years. The boom and bust of the "dot coms," the accompanying investor frenzy and the ultimate implosion of some of the largest and most respected companies in the U.S. were remarkable events to observe from the vantage point of the Sydney and London exchanges. I remember watching the regulatory and legislative response and wondering who in their right mind would agree to be the CEO of a U.S. company in that kind of environment.

My personal answer to that question is simple: Someone who believes in the company and its people.

Sizing Up Our Situation

If the industry resembles a bombed-out village, Duke is one of the few recognizable structures remaining. In hindsight, there is no denying that the company got caught up in the exuberance of the day and participated in the overbuilding of capacity. (To be honest, I often wonder to what extent I might have been sucked into that vortex if I had remained in the industry during that period.)

Obviously, Duke Energy has taken a number of major hits. The stock price at year-end was less than half of what it was at its peak. Credit ratings were reduced twice in 2003. Duke Energy North America has gone from generating profits of over $1 billion in 2001 to a position of generating losses in 2003. Many of the key strategic assumptions that drove Duke Energy in the late '90s proved incorrect, as the world evolved in far different directions. And yet, the underlying assets, the customer base and the market position of the company are sound.

Paul Anderson was appointed Chairman and Chief Executive Officer of Duke Energy effective Nov. 1, 2003. His association with the company began in 1977, when he joined Texas Eastern Corp. as Director of Corporate Planning. Anderson left the company in 1990, following the merger of Texas Eastern Corp. and Panhandle Eastern Corp. He subsequently returned to Panhandle Eastern (later named PanEnergy Corp) to become its Chairman and CEO prior to the merger with Duke Power to create Duke Energy. He served as President and Chief Operating Officer of Duke Energy until 1998, when he left to become CEO and Managing Director of BHP Ltd., an Australian based company. During his tenure at BHP, the company merged with Billiton PLC to form BHP Billiton, listed on both the London and Sydney exchanges. Mr. Anderson retired from BHP Billiton in July 2002.

OUR FINANCIAL PICTURE

(In millions, except where noted)	Years Ended December 31 **2003**	2002	2001	2000	1999
Operating revenues	**$ 22,529**	$ 16,189	$ 18,415	$ 16,228	$ 9,909
(Loss) earnings before interest and taxes from continuing operations[a]	**$ (268)**	$ 3,118	$ 4,236	$ 4,037	$ 2,018
Interest expense	**1,380**	1,097	760	887	583
Minority interest expense[b]	**64**	115	327	306	141
Income tax (benefit) expense from continuing operations	**(707)**	611	1,150	1,036	456
(Loss) income from discontinued operations, net of tax	**(156)**	(261)	(5)	(32)	9
Extraordinary gain, net of tax	**—**	—	—	—	660
Cumulative effect of change in accounting principles, net of tax	**(162)**	—	(96)	—	—
Net (loss) income	**(1,323)**	1,034	1,898	1,776	1,507
Dividends and premiums on redemptions of preferred and preference stock	**15**	13	14	19	20
(Loss) earnings available for common stockholders	**$ (1,338)**	$ 1,021	$ 1,884	$ 1,757	$ 1,487
Common Stock Data					
Basic weighted-average shares outstanding	**903**	836	767	736	729
Basic (loss) earnings per share (from continuing operations)	**$ (1.13)**	$ 1.53	$ 2.59	$ 2.43	$ 1.12
Basic (loss) earnings per share (from discontinued operations)	**$ (0.17)**	$ (0.31)	$ (0.01)	$ (0.04)	$ 0.01
Basic (loss) earnings per share (before extraordinary items and cumulative effect of change in accounting principles)	**$ (1.30)**	$ 1.22	$ 2.58	$ 2.39	$ 1.13
Basic (loss) earnings per share	**$ (1.48)**	$ 1.22	$ 2.45	$ 2.39	$ 2.04
Dividends per share	**$ 1.10**	$ 1.10	$ 1.10	$ 1.10	$ 1.10
Cash flows from operating activities	**$ 3,929**	$ 4,547	$ 4,357	$ 2,011	$ 2,684
Cash flows from investing activities	**$ (931)**	$ (6,809)	$ (6,043)	$ (4,716)	$ (3,751)
Cash flows from financing activities	**$ (2,657)**	$ 2,846	$ 1,354	$ 2,714	$ 1,600
Total assets	**$ 56,203**	$ 60,122	$ 49,624	$ 59,276	$ 34,388
Total debt	**$ 21,952**	$ 22,465	$ 14,185	$ 12,980	$ 9,432
Capitalization					
Common equity	**37%**	36%	41%	37%	42%
Preferred stock[c]	**0%**	1%	1%	1%	1%
Trust preferred securities[c]	**0%**	3%	5%	5%	7%
Total common equity and preferred securities	**37%**	40%	47%	43%	50%
Minority interests[c]	**5%**	5%	7%	9%	6%
Total debt[c]	**58%**	55%	46%	48%	44%

[a] (Loss) earnings before interest and taxes from continuing operations is a non-GAAP financial measure as defined by the Securities and Exchange Commission (SEC) under Regulation G. See page 22 of this report for additional information.

[b] Includes financing expenses related to securities of subsidiaries of $55 million, $130 million, $161 million, $122 million and $87 million for the twelve months ended Dec. 31, 2003, 2002, 2001, 2000 and 1999, respectively. The expense related to these securities is now accounted for in interest expense.

[c] As a result of the implementation of SFAS No. 150 and FIN 46R, approximately $900 million related to trust preferred securities and preferred stock with sinking fund requirements has been reclassified to debt and remains outstanding as of Dec. 31, 2003. Additionally, debt excludes approximately $880 million of debt that has been reclassified as liabilities associated with assets held for sale as of Dec. 31, 2003.

Certain non-GAAP financial measures such as (loss) earnings before interest and taxes from continuing operations and ongoing (loss) earnings per share are used in this report. See page 22 for more information. Included in this Summary Annual Report are financial and operating highlights and consolidated financial statements. Audited financial statements along with related footnotes are included in the company's 2003 SEC Form 10-K. To obtain a copy of the 2003 SEC Form 10-K, please refer to the instructions for Financial Publications inside the back cover of this report.

Relative to many others in the industry, Duke Energy is in an enviable position. Our financial strength provided us choices and flexibility, while others had their options sharply curtailed. We've maintained operational excellence in all of our energy businesses and continued to deliver reliably to our customers. We sold non-core assets to reduce debt, but we weren't forced into a fire sale or to surrender assets vital to our future growth. Our employees, while reduced in number, are re-energized and focused on restoring shareholder value and reclaiming our place as an industry leader.

The work to restore value began in 2003, well before I arrived on the scene. The company reacted forcefully to avoid being caught by the liquidity wave that hurt so many others. In 2003, we generated net proceeds of approximately $2 billion from the sale of non-core assets. We reduced debt and trust preferred securities by $2.2 billion, net of new debt issued and including nearly $400 million of debt assumed in asset sales. We slashed our capital spending to $2.8 billion – versus our original forecast of $3.2 billion – and exited proprietary trading. We undertook a major cost-cutting effort that included significant voluntary and involuntary staff reductions. Our liquidity position is solid, and included over $1 billion in cash and cash equivalents at year-end.

The year culminated in additional dramatic steps to restructure our business portfolio. We have decided to sell our merchant plants in the southeastern U.S. and to forgo further investment in our deferred plants in the West. These actions, combined with others, such as the planned sale of our Australian assets and our exit from Europe, resulted in a $3.4 billion pre-tax write-down in the fourth quarter.

We resolved a number of regulatory and legal issues. In July, the Federal Energy Regulatory Commission (FERC) cleared Duke Energy of charges of withholding electricity from its California power plants. In September, Duke Energy Trading & Marketing announced a $28 million settlement with the Commodity Futures Trading Commission, closing the agency's investigation of natural gas price reporting. In December, we reached a settlement with FERC, ending their inquiry into our trading and marketing practices in the western U.S. market, leaving only the refund proceeding related to the California energy crisis still outstanding at FERC.

I am confident that the tough decisions we made last year will serve us well long-term - but they didn't come without some near-term pain: We reported a net loss of $1.3 billion for 2003, or ($1.48) per share. Our fourth-quarter loss of $2 billion was the largest in company history. Ongoing earnings per share for the year, excluding special items, were $1.28, compared to $1.88 in ongoing EPS in 2002.

Our Investment Proposition

At year-end, we revised our investment proposition to emphasize income and modest growth. The high growth aspirations of the past are simply not in the best interests of our long-term investors. The Board has reaffirmed our commitment to maintain an annual dividend level of $1.10 per share.

As we go forward, our work will be guided by the charter printed on the following page. We have introduced it to our employees, as well as publicly, as the document that defines us as a company, articulates our values, and sets out our management priorities and how we will measure success. I urge you to read the charter and more about the management priorities on the pages that follow. They are the roadmap we will follow to restore our credibility, strengthen our financial performance and meet the needs of our stakeholders.

In 2004, we celebrate the 100th anniversary of Duke Power, the first of Duke Energy's companies. We appreciate those of you who have supported us and have had confidence in us over many years. In my mind, there's no end-goal in the quest to build confidence. The most successful and enduring companies are those that continually strive to do more. When you look at Duke Energy today, I hope you see a company with a renewed sense of purpose, candor and commitment to the long term. As we enter our second hundred years, I pledge to you that Duke Energy will work harder than ever to win your investment, your business and your trust.

Sincerely,

Paul M. Anderson, Chairman of the Board and Chief Executive Officer

March 15, 2004

We are Duke Energy, a leading energy company located in the Americas with an affiliated real estate operation.

Our purpose is to create superior value for our customers, employees, communities and investors through the production, conversion, delivery and sale of energy and energy services.

To provide a stable platform for future growth, we must:

- Deliver on our financial plan and preserve the dividend of $1.10/share.
- Resize and realign our asset portfolio to reflect current and future market realities and to improve return on capital.
- Significantly improve execution of essential management and operating systems, reducing bureaucracy and overhead.
- Build a high performance organization with clear accountabilities in which every individual accepts responsibility and is rewarded for results.
- Restore credibility and earn the trust of employees, customers, suppliers, regulators, legislators, communities and investors.

In conducting our business, we value:

- Stewardship – A commitment to health, safety, environmental responsibility and our communities.
- Integrity – Ethically and honestly doing what we say we will do.
- Respect for the Individual – Embracing diversity and inclusion, enhanced by openness, sharing, trust, teamwork and involvement.
- High Performance – The excitement and fulfillment of achieving superior business results and stretching our capabilities.
- Win-Win Relationships – Having relationships which focus on the creation of value for all parties.
- Initiative – Having the courage, creativity and discipline to lead change and shape the future.

We will be successful when:

- Our investors realize a superior return on their investment.
- Our customers and suppliers benefit from our business relationships.
- The communities in which we operate value our citizenship.
- Every employee starts each day with a sense of purpose and ends each day with a sense of accomplishment.

Duke Energy's Roadmap to Success.

Duke Energy's charter, printed on the facing page, sets out who we are, what we do, how we do it and how we'll know when we succeed. The purpose, values and measures of success will be constants, while the five "musts" are management's immediate priorities. These have shaped the company's financial and operational goals for 2004. As our goals are achieved and new challenges are identified, these priorities will change over time. Below we outline what we must do to provide a stable platform for future growth, and our strategy for getting there.

Deliver on our financial plan and preserve the dividend of $1.10 per share.

Duke Energy took decisive steps in 2003 to improve our financial flexibility. We cut costs, reduced debt and generated cash. We expect to pay down debt by $3.5 to $4 billion in 2004.

We are well-positioned to generate cash this year from the conversion of outstanding equity units, from operations and from asset sales. These funds will be used to reduce debt, pay the dividend and provide capital for maintenance and modest expansion.

Resize and realign our asset portfolio to reflect current and future market realities and to improve return on capital.

In 2003, Duke Energy strengthened and streamlined its portfolio of energy businesses and assets. We sold non-core assets, reduced the size and scope of our domestic merchant energy business and our international operations, and are exiting non-core businesses, including Duke Capital Partners and Duke/Fluor Daniel. These moves reduce our exposure to international and merchant risk, and focus our resources on areas that promise better returns.

A major focus for 2004 will be to complete the execution of the plans we announced for our merchant and international businesses, including the sale of our assets in the southeastern U.S. and Australia, and our exit from Europe.

Our capital investment going forward will be primarily in Duke Power, our franchised electric utility, and Duke Energy Gas Transmission (DEGT), our natural gas pipeline business – both of which deliver stable earnings and strong cash flows. We're investing in these assets to be sure they are well-maintained and we can capture appropriate and attractive high-return growth opportunities. We will also continue to invest capital in Crescent Resources, one of the country's premier real estate development companies, which contributes substantial cash to our enterprise.

Duke Energy Field Services (DEFS) continues to be one of the top players in the North American midstream natural gas sector, enjoying an approximately 20 percent market share in natural gas liquids (NGLs) production. In 2003, DEFS benefited from higher NGL prices and improved "frac spreads" (the difference between the thermal value of NGLs and natural gas). The business also worked to improve cash flow, optimize its assets, realign its contract mix to reduce the impact of commodity price fluctuations, and reduce debt. Going forward, we'll selectively pursue growth opportunities and expand and contract our DEFS asset base in response to changing market cycles.

In merchant and international operations, we are focusing on regions that we expect to yield the highest returns when energy markets improve. In the United States, we will remain in the northeastern, midwestern and western regions where demand is likely to recover sooner than in other regions, and where transmission and regulatory policies better support wholesale power markets. Internationally, we will focus on Latin America. The consolidation of Duke Energy North America (DENA) and Duke Energy International (DEI) reflects our narrowed focus and will result in greater efficiencies.

Duke Energy has an enviable portfolio of energy assets, both regulated and non-regulated. To serve its franchised territory in the Carolinas, Duke Power has the advantage of fuel diversity: nuclear, coal, hydroelectric and natural gas. Our natural gas pipelines and storage facilities are strategically situated to serve major supply basins and high-growth markets. Our merchant plants in the U.S. Northeast, Midwest and West will be well-positioned to contribute strong earnings when demand recovers.

Significantly improve execution of essential management and operating systems, reducing bureaucracy and overhead.

A top-to-bottom expectation of all businesses and corporate functions is to simplify and flatten their organizations and eliminate overlap. For example, the risk management organization now reports to the Chief Financial Officer to align the risk and finance functions and provide a single point of accountability. The role of the Chief Administrative Officer was eliminated. By creating Duke Energy Americas, we combined under one leader the administrative functions for DENA and DEI, and other efficiencies will follow.

The actions we took in 2003 to resize the business and workforce will result in permanent cost savings of more than $200 million a year, and we continue to press for increased efficiency in all areas of the business.

Build a high performance organization with clear accountabilities in which every individual accepts responsibility and is rewarded for results.

Duke Energy's new management team has clearly defined accountabilities, and their compensation is tied to their success. Foremost is achieving the company's minimum earnings per share (EPS) goal of $1.10 – without it, the 12-member executive team will receive zero short-term bonus for the year, no matter how successful they may have been in reaching other goals. The target EPS portion of the incentive plan – which triggers a 100 percent payout for that portion only – is $1.20 a share. In addition to the EPS goal, Executive Committee members and business unit leaders have specific goals that align with and support the management priorities in the charter.

Rewards will be linked to results at all levels of the organization. In 2004, most Duke Energy employees will have EPS as a component of their incentive plan. Additionally for those employees, if 2004 earnings fall below $1.10 a share, the payout for all measures will be capped at 50 percent.

The ultimate example of pay tied to performance is the compensation plan for CEO Paul Anderson. Anderson's compensation is entirely stock-based with a provision that all shares received must be held until he leaves the company. Additionally, there is no provision for a cash severance payment should his employment be terminated by the Board of Directors before his contract ends in 2007.

If our compensation plan emphasizes accountability, so do the company's governance practices. Even before Sarbanes-Oxley was signed into law in 2002, Duke Energy's policies and practices guarded against conflict of interest, supported independent and involved oversight of management by the Board of Directors, and provided other safeguards now required by the legislation or recommended by the New York Stock Exchange.

Duke Energy is subject to regulatory codes and standards of conduct that address business activities between regulated companies and their affiliates. These rules prevent regulated businesses from subsidizing the activities of their affiliates, and prevent the affiliates from gaining an unfair advantage because of their relationship with the regulated businesses. Duke Energy complies with both the letter and the spirit of these standards and works to ensure that all employees understand and follow them.

Like ethical conduct, safety is a key aspect of successful performance. Duke Energy's long-range safety goal is simple – zero injuries, work-related illnesses and fatalities. Management and employees must continually renew their commitment to safety in order to reach that goal. Improvements in corporate-wide safety results begin by establishing accountability at every level, starting with the company's leaders. Business units are expected to set challenging safety targets, and to provide quarterly safety performance reviews. We foster a culture in which individual employees accept accountability for the safety of their co-workers, their customers, their communities and themselves.

Restore credibility and earn the trust of employees, customers, suppliers, regulators, legislators, communities and investors.

There is no doubt that our reputation has taken some hits. We are committed to restoring confidence in Duke Energy by reliably serving our customers, by delivering superior returns to investors, by being good neighbors in communities where we operate, and by providing our employees with a sense of purpose and direction.

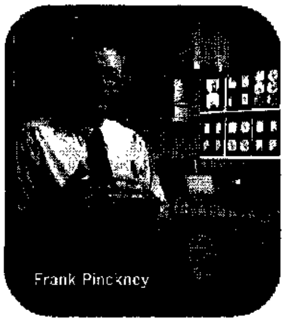
Duke Energy is recommitting itself to creating win-win relationships with every customer we serve, and with regulatory agencies charged with representing consumer interests.

We're working hard to enhance the customer experience in every facet of Duke Energy. From ensuring natural gas delivery to a Canadian power generator during the August blackout, to helping a South Carolina hospital operate around the clock, to supplying reliable electricity to a manufacturer in Brazil – we're committed to delivering dependable and cost-effective energy and service. You'll hear directly from a few of our customers in the pages that follow.

We work openly and productively with the regulatory agencies that oversee our businesses. Duke Power, for example, has been able to work with utility commissions in North Carolina and South Carolina to develop win-win approaches to such issues as clean air legislation and the company's resulting environmental investments.

We bring more than natural gas and power to our communities. For instance, DEGT is committed to increasing aboriginal participation in its workforce in British Columbia through employment and contracting opportunities. Duke Power has renewed its commitment to economic development in the Carolinas, partnering with government and community interests to attract new industry and jobs to the region. Reflecting the company's community spirit, Duke Energy employees and retirees volunteered more than 235,000 hours to nonprofit organizations in 2003.

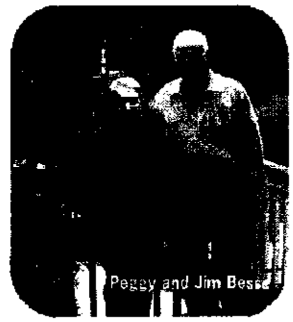
Duke Energy is committed to restoring its reputation as an industry leader. In all of our interactions with investors, customers, neighbors and employees, we are working hard to regain their trust.



Frank Pinckney

"As one of the largest hospital systems in the state, our physicians, nurses and patients depend on Duke Power. Together we save lives and keep patients breathing hour after hour, every day of the week."

Frank Pinckney, CEO and President
Greenville Hospital System
Greenville, S.C.



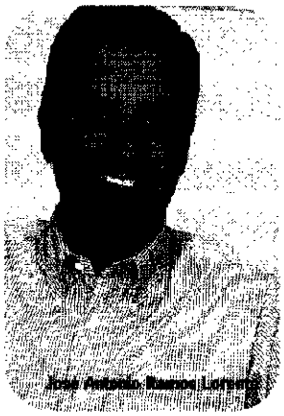
Peggy and Jim Besse

"In view of the prices of other services available to retirees who live on fixed incomes, such as health insurance and medication, you and your company are standouts for efficiency and concern for your customers."

Peggy and Jim Besse,
Duke Power customers
Hickory, N.C.

"For a glass packaging manufacturer, electric energy is one of the main raw materials in the industrial process. Choosing Duke Energy as our electric energy supplier assured Cisper a real *competitive advantage.* Our partnership has always been based on clear and objective negotiations."

José Antonio Ramos Lorente,
President, Cisper S/A
(affiliated company of Owens-Illinois Inc.)
São Paulo, São Paulo, Brazil



José Antonio Ramos Lorente

"Crescent Resources has been exceptionally responsive in working with our organization over the years. Our third land purchase from the company is now pending, and we hope to continue to partner with Crescent in our efforts to protect the natural resources and water quality of the Catawba River valley."

D. Lindsay Pettus, President
The Katawba Valley Land Trust
Lancaster, S.C.

"We have worked closely with Duke Energy when we wanted to obtain more ownership of electric generation facilities. Duke Energy's experience and ability to react to our needs has made them a company with whom we have enjoyed a positive business relationship."

Rick Coons,
Chief Operating Officer
Wabash Valley Power Association
Indianapolis, Ind.

Rick Coons

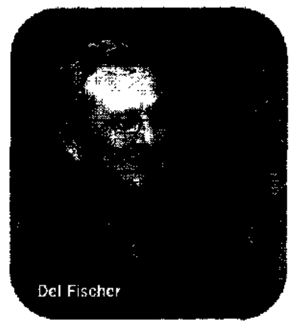
"Texas Parks and Wildlife has accomplished a lot at San *Jacinto Battleground over the past few years. Restoration,* revegetation, interpretation and construction projects have become realities, thanks to our partners. Some of our partners donate materials or money. Other partners donate volunteer labor. Duke Energy contributes both. TPW and Duke Energy are not just partners; we're members of a team, and in some ways, *that's the most valuable* donation of all!"

Ted Hollingsworth,
Cultural Resources Manager
Texas Parks and Wildlife Dept.
La Porte, Texas

Ted Hollingsworth

"Over the last 10 years, the Capital City has enjoyed tremendous economic growth, placing a great demand on the infrastructure. One of the City's greatest assets is the power plant. In 1996 the City of Dover became partners with Duke Energy for the management and operation of that plant. I can honestly say that was one of the smartest decisions this City has ever made to protect that asset."

James L. Hutchison, Mayor
City of Dover, Del.



Del Fischer

"While planning our Pinedale field development, we recognized the need for a large pipeline expansion to meet our growth projections. We were *pleased that Duke was willing* to work out a mutually beneficial solution that met both our timing and capacity needs."

Del Fischer,
Gas Planning and Transportation
Shell Exploration & Production Co.
Houston, Texas

James L. Hutchison

The Roberts

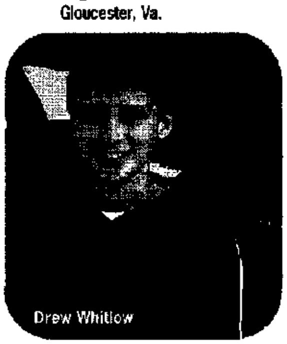
Ken Lacivita

"During the massive power blackout in August 2003, Union Gas personnel were able to assist OPGI in sourcing and supplying natural gas to the Lennox Generating Station near Kingston, Ontario. By ensuring natural gas was available, the station was able to continue to operate and contributed to meeting the electricity needs of Ontario consumers during a very difficult time."

Ken Lacivita,
Director, Electricity Trading
Ontario Power Generation Inc.
Toronto, Ontario

"After Isabel ripped through, Gloucester was left powerless and gloomy. We wouldn't have gotten power as fast as we did if it weren't for your crews. I thought my family was not going to have power for a month. We got it in a week! Thank you so much for all you did."

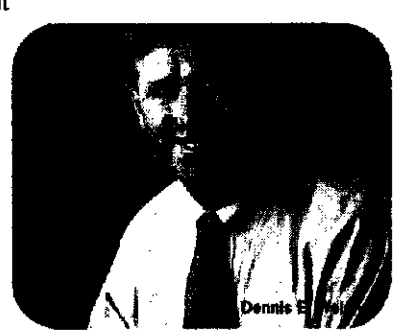
Drew Whitlow, 7th grade student
Page Middle School
Gloucester, Va.



Drew Whitlow

"Our relationship with Duke Energy is all about them understanding our business, from our perspective, as evidenced during a compressor station outage this winter. They shared critical information with us, so that we could understand how the outage might affect our system operations. We consider the Duke team to be our partner in delivering safe, reliable energy to our customers, every day."

Dennis E. Welch,
President and
Chief Operating Officer
Yankee Gas Services Co.
Berlin, Conn.



Dennis E. Welch

"Sugarloaf was the first place we saw that had all the things we wanted in one place – golf, lakes, a pool for our kids, sidewalks for bikes, good schools and a sense of security."

Dawn and Scott Roberts,
Crescent community homeowners
Sugarloaf Country Club,
Duluth, Ga.

We come to work every day to serve these and all of our customers. We know that we will succeed as a company if we serve them well. On the following pages, we describe our main business units, their primary areas of focus, and how they are meeting customer expectations and responding to changing markets.

WHAT WE DO

Duke Energy is a diversified energy company with a portfolio of natural gas and electric businesses, both regulated and non-regulated, and an affiliated real estate company. Duke Energy supplies, delivers and processes energy for customers in North America and selected international markets. Headquartered in Charlotte, N.C., Duke Energy is a Fortune 500 company traded on the New York Stock Exchange under the symbol DUK.

DUKE POWER

Profile: Duke Power is one of the nation's largest electric utilities and provides safe, reliable, competitively priced electricity and value-added products and services to more than 2 million customers in North Carolina and South Carolina. In 2004, Duke Power celebrates 100 years of service. The company operates three nuclear generating stations, eight coal-fired stations, 31 hydroelectric stations and numerous combustion turbine units. Total system generating capability is approximately 19,900 megawatts. Duke Power is based in Charlotte.

Operating Data:

	2003	2002	2001	2000	1999
Franchised Electric					
Sales, gigawatt-hours	**82,828**	83,783	79,685	84,766	81,548
Nuclear capacity factor[a]	**91%**	95%	92%	92%	90%
Average number of customers	**2,160,000**	2,117,000	2,117,000	2,072,000	2,023,000

[a] Includes 100 percent of Catawba Nuclear Station, which is 12.5 percent owned by Duke Power.

Performance Highlights:

- Duke Power achieved a critical milestone last year, with the Nuclear Regulatory Commission's renewal of Catawba and McGuire Nuclear Stations' operating licenses – allowing the stations to continue providing electricity, jobs and revenue into the 2040s. Oconee Nuclear Station's license renewal was approved in 2000. Duke Power is the first utility in the United States to have seven nuclear units with extended licenses.
- Oconee celebrated 30 years of operation in 2003, and was the first U.S. nuclear station to reach 500 million megawatt-hours of electric generation. McGuire generated more electricity than in any previous year, and also set station records for reliability and cost efficiency. Even with planned maintenance and refueling outages, Duke Power's three nuclear stations produced at more than 91 percent of their capacity in 2003.
- Duke Power's fossil and hydroelectric fleets achieved 98 percent commercial availability for the second year, and the hydro stations set a new generation record of 6.4 million megawatt-hours.
- Duke Power is investing nearly $2.2 billion in emission controls for its fossil-fueled power plants over the next decade, to bring air emissions well under current federal limits. At Belews Creek, Duke Power's largest coal-fired station, new environmental equipment is expected to reduce the utility's nitrogen oxide emissions by 75 percent from 1998 levels by this summer.
- The formal relicensing process is underway for Duke Power's Catawba-Wateree hydroelectric operations. The utility is working closely with stakeholder groups to ensure that its hydro facilities continue to serve customers and communities in an environmentally responsible manner.
- In 2003, Duke Power renewed its commitment to economic development in its service area, the surest way to draw new customers to the region and keep existing ones. The Carolinas have seen substantial and ongoing declines in traditional industries such as textiles, furniture, chemicals and tobacco, and Duke Power is working with government and community interests to spur a more diverse business and manufacturing economy. It's working – General Dynamics has moved a division headquarters to Charlotte and will open a plant in the area, and Sterilite is building a manufacturing facility in Laurens, S.C.

- Duke Power received the 2003 Edison Electric Institute Emergency Response Award, recognizing the swift restoration of electric service to 1.4 million customers affected by the December 2002 ice storm. That unprecedented effort heightened the utility's readiness for weather events like Hurricane Isabel, which hit the U.S. East Coast in September. After restoring service to thousands of Duke Power customers, crews moved on to help Dominion repair Isabel's damage in harder-hit areas in Virginia and eastern North Carolina.
- Duke Power launched an electronic billing and payment service in 2003. This new service allows customers to receive and pay their bills online. Nearly 5 percent of customers have already signed up for e-Bill, saving the mailing of more than a million bills annually. If just half of Duke Power's customers were to choose this option, the utility would save approximately $2 million per year.
- Mill Creek Combustion Turbine Station is the newest addition to Duke Power's generation fleet. The $300 million, 640-megawatt natural gas-fired station in Cherokee County, S.C., can generate enough power to serve more than 500,000 homes.

Strategy Going Forward:

- Deliver on the financial plan through management of cash, costs and capital, and through win-win regulatory policy.
- Operate assets with superior safety, reliability, efficiency, availability and responsibility.
- Improve customer satisfaction and deliver valued products and services.
- Create and realize opportunities for sustainable sales growth.
- Earn trust and build confidence with employees, customers, communities, regulators and elected officials.

DUKE ENERGY GAS TRANSMISSION

Profile: Duke Energy Gas Transmission (DEGT) transports and stores natural gas from North America's major supply areas for customers in the northeastern and southeastern United States and in Canada. DEGT also distributes natural gas to retail customers in Ontario, and gathers and processes natural gas for customers in western Canada. DEGT is based in Houston.

Operating Data:

	2003	2002	2001	2000	1999
Natural Gas Transmission					
Throughput, trillion British thermal units (TBtu)[a]	**3,362**	3,160	1,781	1,771	1,893
Storage capacity, billion cubic feet	**257**	254	101	98	75

[a] Represents share of capacity owned by DEGT.

Performance Highlights:

- DEGT capped a great year in 2003 by placing five major pipeline expansion projects into service in three key growth regions – in time for the winter heating season. The five expansions provide a combined 850 million cubic feet per day of added capacity for customers in the northeastern and southeastern United States, eastern Canada, British Columbia and the U.S. Pacific Northwest.
- DEGT is moving forward with plans to construct the Dominion Expansion Project, which will transport natural gas for distribution by DEGT customer Dominion Transmission in Maryland and Virginia, increasing the reliability and efficiency of natural gas supplies in the Mid-Atlantic region.
- January 2004 brought the U.S. Northeast some of the lowest temperatures in two decades. DEGT's Algonquin and Texas Eastern systems had some of their top delivery days in company history in that region. DEGT's pipelines and storage facilities met shippers' supply demands with the consistently reliable service they expect from DEGT. More than 99 percent of DEGT's Northeast shippers whose contracts came up for renewal in 2003 showed their satisfaction by renewing agreements with the company.

- Natural gas storage has become an increasingly critical part of the energy infrastructure in North America. In August, customers began preparing for winter by storing natural gas in the new Saltville Gas Storage facility in southwest Virginia, the only salt cavern storage facility in the South Atlantic market. Jointly developed by DEGT and NUI Corp.'s Virginia Gas Co., the field has storage capacity for 1 billion cubic feet of natural gas; that capacity will double in 2004 and expand to a planned 6 billion cubic feet by 2007. DEGT also has storage capacity in Texas, Louisiana, Pennsylvania and Maryland, and the largest natural gas storage facility in North America, Union Gas' Dawn facility in Ontario.
- The Gulfstream Natural Gas System, jointly developed by DEGT and Williams, signed a 23-year agreement with Florida Power & Light Co. (FPL), to transport up to 350 million cubic feet of natural gas per day beginning in 2005. Gulfstream, the first interstate transmission pipeline across the Gulf of Mexico, is extending its Florida mainline by approximately 110 miles to enable two FPL plants to serve an additional 400,000 customers on Florida's East Coast.
- DEGT's Union Gas provided transportation and distribution of 1,250 billion cubic feet of natural gas and experienced a net increase of 24,000 customers.
- DEGT's U.S. operations recorded their lowest ever number of preventable safety incidents in 2003, achieving a 17.6 percent reduction over 2002. Eighty-two U.S. transmission locations were accident-free, and five have recorded more than 1 million work-hours without a lost-time injury.
- In Canada, DEGT's BC Pipeline and Field Services group exceeded its safety performance targets by 45 percent for personal injuries and 22 percent for vehicle accidents, and incurred no lost-time incidents.
- In line with Duke Energy's strategy to strengthen its financial position by selling non-core assets, the company sold ownership interests in a number of pipeline systems and related facilities in 2003.

Strategy Going Forward:

- Produce superior financial results through increased productivity and balanced growth.
- Provide superior customer service.
- Optimize existing asset portfolio.
- Capture efficiencies and control costs.
- Develop new high-return expansion projects.

DUKE ENERGY FIELD SERVICES

Profile: Duke Energy Field Services (DEFS) gathers, processes, transports, markets and stores natural gas, and produces, transports and markets natural gas liquids (NGLs) like propane, butane and ethane. DEFS gathers natural gas from producers' wells in western Canada and from Wyoming to the Gulf Coast, and processes it at more than 60 plants.

Headquartered in Denver, DEFS is the largest producer of NGLs in North America – with twice the production of its nearest competitor – and one of the largest marketers. DEFS also owns the general partner of TEPPCO, a master limited partnership which owns and operates pipelines for refined products, NGLs and crude oil, and owns natural gas gathering assets. Duke Energy owns approximately 70 percent of DEFS, and ConocoPhillips owns the remainder.

Operating Data:

	2003	2002	2001	2000	1999
Field Services					
Natural gas gathered and processed/transported, TBtu/day	**7.7**	8.1	8.3	7.3	4.9
Natural gas liquids production, thousand barrels per day	**365.3**	388.7	394.0	354.9	186.3
Average natural gas price per million Btu	**$ 5.39**	$ 3.22	$ 4.27	$ 3.89	$ 2.27
Average natural gas liquids price per gallon	**$ 0.53**	$ 0.38	$ 0.45	$ 0.53	$ 0.34

Performance Highlights:

- DEFS has benefited from higher NGL prices, which have risen with increasing demand for NGLs along with natural gas and crude oil, and the "frac spread" (the difference between the thermal value of NGLs and natural gas) has increased as well. DEFS continues to lead the NGL industry with 20 percent of market share.
- DEFS has realized strong margins from its natural gas processing business, especially on percent-of-proceeds contracts, under which DEFS keeps a percentage of the natural gas and NGLs as payment for services.
- One of DEFS' strategies for 2003 was to support the growth strategy at TEPPCO. TEPPCO expanded the pipeline and processing capacity on its Jonah Gas Gathering System in Wyoming, and increased to 50 percent its ownership interest in the Centennial Pipeline from the Gulf Coast to the Midwest.
- DEFS sold several non-strategic assets according to plan in 2003, including various gas processing plants and gathering pipelines in the Gulf Coast region and Oklahoma.

Strategy Going Forward:

- Capitalize on size and focus of existing operations.
- Be a top-3 player in every producing region where DEFS has assets.
- Optimize and rationalize the asset base.
- Focus on operational and commercial excellence.
- Maintain strong financial position and self-funding status.
- Support the growth of TEPPCO.

DUKE ENERGY AMERICAS

As 2003 drew to a close, Duke Energy took a close look at opportunities to streamline operations for higher efficiency. As a result, in January 2004, the major merchant energy businesses, Duke Energy North America (DENA) and Duke Energy International (DEI), were combined into Duke Energy Americas, based in Houston. These businesses will more narrowly focus on key markets in North America and Latin America.

Duke Energy North America

Profile: Duke Energy North America operates merchant power generation facilities, and markets electricity, natural gas, energy management and related services to wholesale customers throughout North America.

Of all of Duke Energy's business units, DENA faced the toughest challenges in 2003. A period of rapid growth in merchant power markets was followed by regulatory and market upheavals and the aftershocks of Enron's collapse. An oversupply of merchant generation in many regions and low spark spreads (the difference between the cost of natural gas and the price of the electricity it generates) have prevented many DENA facilities from generating power profitably. As a result, the company made the strategic decision to exit the Southeast region in 2004, but to retain operations in the West, Northeast and Midwest regions – markets that have value for the company long-term.

Operating Data:

	2003	2002	2001	2000	1999
Duke Energy North America					
Actual plant production, gigawatt-hours	**24,046**	24,962	20,516	18,523	11,307
Capacity in operation, megawatts[a]	**15,820**	14,157	6,799	5,134	3,532

[a] Represents share of capacity owned by DENA.

Performance Highlights:

- DENA reduced the scope and scale of its trading and marketing organization to align with current market conditions, limited commercial transactions to those that directly benefit DENA operations and customers, and implemented new levels of control and risk management.
- In May, DENA announced it would end proprietary (purely financial) trading, which typically represented less than 10 percent of DENA's gross margin. In 2003, DENA also began to wind down the Duke Energy Trading & Marketing joint venture, which is 60 percent owned by Duke Energy and 40 percent by ExxonMobil. DENA's stand-alone trading and marketing operation continues with a focus around the company's own assets.
- DENA sold 15 significant new tolls related to its plants. A toll is an agreement to sell all or part of the generating capacity of a power plant for a fee. Duke Energy expects tolling deals to play an increasingly important role in merchant energy, allowing DENA to capture margin at relatively low risk.
- In 2003, DENA initiated a new customer relationship program, enhancing and renewing ties with key providers and buyers in the areas where DENA plants are located.
- Consistent with its sharpened focus on its merchant natural gas-fired fleet, DENA sold its interest in American Ref-Fuel, which converts municipal solid waste into energy, and Duke Energy Hydrocarbons, which was involved in the exploration and production of natural gas and petroleum, primarily in the Gulf of Mexico.
- As DENA employees faced tough challenges in 2003, their resolve to work safely resulted in a 50 percent reduction in recordable injuries.

Strategy Going Forward:

- Selectively reduce merchant energy exposure by selling plants in the southeastern United States, and by selling DENA's interest in deferred plants in Washington, Nevada and New Mexico, or seeking a partner to fund their completion.
- Rationalize the natural gas transportation and storage business around DENA's generation assets.
- Return the base business to profitability as the market recovers.
- Retain an option for future regional growth in wholesale merchant energy.

Duke Energy International

Profile: Duke Energy International operates power generation facilities, and engages in sales and marketing of electric power and natural gas outside the United States and Canada. Its primary focus is on power generation activities in Latin America, where it owns approximately 4,100 net megawatts of capacity in seven countries.

During 2003, DEI made the strategic decision to exit the European and Asia-Pacific markets, reducing the overall exposure of Duke Energy to international markets. DEI sold its investment in Indonesia, a power plant in northwest France and its Dutch gas marketing business, collectively generating gross proceeds of over $400 million for Duke Energy. Duke Energy retains a diversified portfolio of generating assets that are well-positioned to benefit from strengthening energy markets and economies in Latin America. This table presents operating data for DEI's continuing operations.

Operating Data:

	2003	2002	2001	2000	1999
International Energy					
Sales, gigawatt-hours	**16,374**	18,350	15,749	14,154	4,812
Capacity in operation, megawatts[a]	**4,121**	3,917	3,968	3,768	2,415

[a] Represents share of capacity owned by DEI.

Performance Highlights:

- 2003 was a solid year from an operating standpoint for DEI's continuing operations in Latin America and its investment in National Methanol Company in Saudi Arabia.
- Strong operating results were driven by successful recontracting efforts in Brazil, stronger market prices in Peru, completion of the second phase of a greenfield plant in Guatemala, solid results from National Methanol and significant cost reductions of approximately $30 million over 2002.
- DEI Guatemala brought the second phase of the 160-megawatt Planta Arizona on line, and is completing a conversion this year which will allow the plant to run on Orimulsion® in addition to fuel oil. The plant's dual-fuel capability will position Planta Arizona as one of the most flexible, efficient and low-cost generators in the region.
- DEI Peru became the first company in Peru, and the first Duke Energy company, to obtain simultaneous international certifications for operations management (ISO 9001), environmental management (ISO 14001) and occupational health and safety practices (OHSAS 18001).
- For the second consecutive year, DEI Brazil Paranapanema received the Medalha Eloy Chaves Award as recognition for the best safety record in the Brazilian electric generation sector. It is the only company ever to have received this award for two consecutive years. DEI Brazil also reached 4 million work-hours without a lost-time incident.

Strategy Going Forward:

- Focus on Latin America, with an emphasis on increasing overall returns through:
  - Organic growth through sales and marketing efforts
  - Asset optimization for all facilities
  - Cost reduction
  - Portfolio/balance sheet management.
- Identify and assess opportunities in Latin America to capitalize on economic growth, regulatory reform and strengths of the existing portfolio.
- Complete exit from the European and Asia-Pacific regions.

CRESCENT RESOURCES

Profile: As part of Duke Energy for over 40 years, Crescent Resources manages land holdings and develops high-quality commercial, residential and multi-family real estate projects in nine states. Crescent Resources has received numerous awards for its environmentally sensitive property development strategies and partnerships with environmental and wildlife groups. The company is based in Charlotte.

Operating Data:

	2003	2002	2001	2000	1999
Crescent Resources					
Residential lots sold	**2,060**	1,221	1,075	955	1,049
Commercial square footage sold, in millions	**1.7**	1.2	3.1	2.0	2.0
Multi-family units sold	**950**	—	—	—	—
Surplus (legacy) land sold, acres	**5,088**	10,982	11,402	8,562	29,648

Performance Highlights:

- Crescent is the master developer of Potomac Yard, a 300-acre mixed-use development adjacent to Reagan National Airport in Arlington and Alexandria, Va. The approved plans for Potomac Yard include high-quality mixed-use communities of townhouses, apartments, hotels, retail stores, offices, open space, pedestrian-friendly neighborhoods, parks, playfields and a transit system. In 2003, Crescent sold two parcels of land for apartment and condominium units and retail developments, and began work on two office buildings.

- Two major transactions underway in 2003 demonstrate Crescent's commitment to strike a balance between property developed in an environmentally sensitive manner and land sold for long-term preservation.
  - The N.C. Wildlife Resources Commission will manage the 4,400-acre Needmore area that hosts a diverse array of aquatic and forest wildlife along a 27-mile stretch of the Little Tennessee River in the N.C. mountains. Supported by individual donations and environmental groups, the N.C. chapter of The Nature Conservancy worked with the state and Crescent to facilitate the purchase, completed in January 2004.
  - In December 2003, Crescent accepted a letter of intent from The Katawba Valley Land Trust (KVLT) to buy the Heritage Tract, a 2,000-acre area of environmental, cultural and historical significance along the Catawba River in South Carolina. Crescent has sold more than 1,200 acres to KVLT for the expansion of Landsford Canal State Park, home of the world's largest known colony of the rare Rocky Shoals spider lilies. In recent years, Crescent has also conveyed several conservation easements along the stream banks feeding into the Catawba River to KVLT for permanent stewardship.
- More than one-third of the property in Palmetto Bluff, Crescent's 20,000-acre recreational and residential community in South Carolina's lowcountry, will remain undeveloped, including a 6,500-acre managed forest. Crescent has sold close to $50 million in residential real estate at Palmetto Bluff since sales opened last year. A luxury inn and spa and an 18-hole Nicklaus Signature Golf Course are set to open in 2004.
- In 2003, Crescent maintained strong market share in its residential markets.
  - The company sold 57 percent of the total value of homesites with an average price of $50,000 or more in new communities in the greater Charlotte, N.C., area.
  - In the metro Atlanta area, Sugarloaf Country Club has been the top-selling luxury golf club community for million-dollar homes for the past six years.
  - In Palm Coast, Fla., Crescent's residential venture partner LandMar Group's Grand Haven exceeded 2003 sales projections by 55 percent.
  - Crescent welcomed the first families to its new country club community in the Atlanta area, the River Club, on the Chattahoochee River in Suwanee, Ga.
  - Crescent opened three new communities at Lake Keowee in South Carolina, and announced plans for a new family-oriented residential development near Lake Norman in North Carolina.
- Since establishing its retail division three years ago, Crescent's strategy has been to sell select neighborhood retail centers it develops and re-invest in the development of new retail centers. The company closed four sales in the month of December 2003 alone for more than $50 million, and has five retail centers under development.
- Crescent's multi-family division realized a gain of $11.6 million when it sold two apartment communities in 2003. Both Lighthouse Court in the Jacksonville, Fla., area and CrossWynde in the Tampa vicinity opened less than two years ago.

Strategy Going Forward:

- Generate earnings through:
  - Opportunity-driven development in carefully selected target markets
  - Land sales that maximize the return to shareholders.
- Continue to focus on existing business lines, executing a proven development strategy without significantly increasing risk.
- Continue to generate significant cash flows through asset sales, while maintaining current capital expenditure levels.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions)	Years Ended December 31 2003	2002	2001
Operating Revenues			
Non-regulated electric, natural gas, natural gas liquids and other	**$ 14,561**	$ 9,109	$ 12,405
Regulated electric	**5,026**	4,880	5,088
Regulated natural gas	**2,942**	2,200	922
Total operating revenues	**22,529**	16,189	18,415
Operating Expenses			
Natural gas and petroleum products purchased	**11,568**	5,436	6,986
Fuel used in electric generation and purchased power	**2,087**	2,191	2,022
Operation and maintenance	**3,959**	3,441	3,991
Depreciation and amortization	**1,803**	1,515	1,262
Property and other taxes	**527**	535	431
Impairment and other related charges	**2,956**	364	—
Impairment of goodwill	**254**	—	36
Total operating expenses	**23,154**	13,482	14,728
(Losses) Gains on Sales of Other Assets, net	**(199)**	32	238
Operating (Loss) Income	**(824)**	2,739	3,925
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	**123**	218	164
Gains on sales of equity investments	**279**	32	—
Other income and expenses, net	**154**	129	147
Total other income and expenses	**556**	379	311
Interest Expense	**1,380**	1,097	760
Minority Interest Expense	**64**	115	327
(Loss) Earnings from Continuing Operations Before Income Taxes	**(1,712)**	1,906	3,149
Income Tax (Benefit) Expense from Continuing Operations	**(707)**	611	1,150
(Loss) Income from Continuing Operations	**(1,005)**	1,295	1,999
Discontinued Operations			
Net operating loss, net of tax	**(27)**	(261)	(5)
Net loss on dispositions, net of tax	**(129)**	—	—
Loss from Discontinued Operations	**(156)**	(261)	(5)
(Loss) Income Before Cumulative Effect of Change in Accounting Principle	**(1,161)**	1,034	1,994
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest	**(162)**	—	(96)
Net (Loss) Income	**(1,323)**	1,034	1,898
Dividends and Premiums on Redemption of Preferred and Preference Stock	**15**	13	14
(Loss) Earnings Available for Common Stockholders	**$ (1,338)**	$ 1,021	$ 1,884

CONSOLIDATED BALANCE SHEETS

(In millions)	December 31 2003	2002
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 1,160**	$ 874
Receivables (net of allowance for doubtful accounts of $280 at 2003 and $349 at 2002)	**2,888**	4,861
Inventory	**1,156**	1,134
Assets held for sale	**424**	—
Unrealized gains on mark-to-market and hedging transactions	**1,566**	2,144
Other	**694**	887
Total current assets	**7,888**	9,900
Investments and Other Assets		
Investments in unconsolidated affiliates	**1,398**	2,015
Nuclear decommissioning trust funds	**925**	708
Goodwill	**3,962**	3,747
Notes receivable	**260**	589
Unrealized gains on mark-to-market and hedging transactions	**1,857**	2,480
Assets held for sale	**1,444**	—
Other	**1,117**	1,645
Total investments and other assets	**10,963**	11,184
Property, Plant and Equipment		
Cost	**47,157**	48,677
Less accumulated depreciation and amortization	**12,171**	11,298
Net property, plant and equipment	**34,986**	37,379
Regulatory Assets and Deferred Debits		
Deferred debt expense	**275**	263
Regulatory asset related to income taxes	**1,152**	936
Other	**939**	460
Total regulatory assets and deferred debits	**2,366**	1,659
Total Assets	**$ 56,203**	$ 60,122

(in millions)	December 31 2003	2002
LIABILITIES AND COMMON STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 2,331**	$ 3,637
Notes payable and commercial paper	**130**	915
Taxes accrued	**—**	156
Interest accrued	**304**	310
Liabilities associated with assets held for sale	**651**	—
Current maturities of long-term debt and preferred stock	**1,200**	1,331
Unrealized losses on mark-to-market and hedging transactions	**1,283**	1,918
Other	**1,799**	1,770
Total current liabilities	**7,698**	10,037
Long-term Debt, including debt to affiliates of $876 at 2003	**20,622**	20,221
Deferred Credits and Other Liabilities		
Deferred income taxes	**4,120**	4,834
Investment tax credit	**165**	176
Unrealized losses on mark-to-market and hedging transactions	**1,754**	1,548
Liabilities associated with assets held for sale	**737**	—
Other	**5,524**	4,893
Total deferred credits and other liabilities	**12,300**	*11,451*
Commitments and Contingencies		
Guaranteed Preferred Beneficial Interests in Subordinated Notes of Duke Energy Corporation or Subsidiaries	**—**	1,408
Minority Interests	**1,701**	1,904
Preferred and Preference Stock		
Preferred and preference stock with sinking fund requirements	**—**	23
Preferred and preference stock without sinking fund requirements	**134**	134
Total preferred and preference stock	**134**	157
Common Stockholders' Equity		
Common stock, no par, 2 billion shares authorized; 911 million and 895 million shares outstanding at December 31, 2003 and 2002, respectively	**9,519**	9,236
Retained earnings	**4,060**	6,417
Accumulated other comprehensive income (loss)	**169**	(709)
Total common stockholders' equity	**13,748**	14,944
Total Liabilities and Common Stockholders' Equity	**$ 56,203**	$ 60,122

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	Years Ended December 31 2003	2002	2001
Cash Flows from Operating Activities			
Net (loss) income	**$ (1,323)**	$ 1,034	$ 1,898
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation and amortization (including amortization of nuclear fuel)	**1,987**	1,692	1,450
Cumulative effect of change in accounting principles	**162**	—	96
Gain on sales of equity investments and other assets	**(86)**	(81)	(238)
Impairment charges	**3,495**	545	36
Deferred income taxes	**(534)**	495	129
Purchased capacity levelization	**194**	175	156
Contribution to company-sponsored pension plan	**(181)**	—	—
(Increase) decrease in			
Net realized and unrealized mark-to-market and hedging transactions	**(15)**	596	91
Receivables	**1,126**	12	3,166
Inventory	**(30)**	134	(192)
Other current assets	**(77)**	(335)	694
Increase (decrease) in			
Accounts payable	**(1,030)**	798	(3,545)
Taxes accrued	**(168)**	(332)	183
Other current liabilities	**79**	(194)	325
Other, assets	**349**	380	351
Other, liabilities	**(19)**	(372)	(243)
Net cash provided by operating activities	**3,929**	4,547	4,357
Cash Flows from Investing Activities			
Capital expenditures, net of refund	**(2,471)**	(4,924)	(5,930)
Investment expenditures	**(290)**	(641)	(1,093)
Acquisition of Westcoast Energy Inc., net of cash acquired	**—**	(1,707)	—
Net proceeds from the sale of equity investments and other assets, and sales of and collections on notes receivable	**1,966**	516	943
Other	**(136)**	(53)	37
Net cash used in investing activities	**(931)**	(6,809)	(6,043)
Cash Flows from Financing Activities			
Proceeds from the			
Issuance of long-term debt	**3,009**	5,114	2,673
Issuance of common stock and common stock related to employee benefit plans	**277**	1,323	1,432
Payments for the redemption of			
Long-term debt	**(2,849)**	(1,837)	(1,298)
Preferred and preference stock and preferred member interests	**(38)**	(88)	(33)
Guaranteed preferred beneficial interests in subordinated notes	**(250)**	—	—
Notes payable and commercial paper	**(1,702)**	(1,067)	(246)
Distributions to minority interests	**(2,508)**	(2,260)	(3,063)
Contributions from minority interests	**2,432**	2,535	2,733
Dividends paid	**(1,051)**	(938)	(871)
Other	**23**	64	27
Net cash (used in) provided by financing activities	**(2,657)**	2,846	1,354
Changes in cash and cash equivalents associated with assets held for sale	**(55)**	—	—
Net increase (decrease) in cash and cash equivalents	**286**	584	(332)
Cash and cash equivalents at beginning of period	**874**	290	622
Cash and cash equivalents at end of period	**$ 1,160**	$ 874	290
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	**$ 1,324**	$ 1,011	$ 733
Cash (refunded) paid for income taxes	**(18)**	$ 344	$ 770
Significant non-cash transactions:			
Acquisition of Westcoast Energy Inc.			
Fair value of assets acquired	**$ —**	$ 9,254	$ —
Liabilities assumed, including debt and minority interests	**—**	8,047	—
Issuance of common stock	**—**	1,702	—
Capital lease obligations related to property, plant and equipment	**$ —**	$ 117	$ —

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

				Accumulated Other Comprehensive Income (Loss)			
(In millions)	Common Stock Shares	Common Stock	Retained Earnings	Foreign Currency Adjustments	Net Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	Total
Balance December 31, 2000	**739**	**$4,797**	**$5,379**	**$(120)**	**$ —**	**$ —**	**$10,056**
Net income			1,898				1,898
Other comprehensive income							
Cumulative change in accounting principle[a]					(921)		(921)
Foreign currency translation adjustments				(187)			(187)
Net unrealized gains on cash flow hedges[c]					1,324		1,324
Reclassification into earnings from cash flow hedges[d]					84		84
Total comprehensive income							2,198
Dividend reinvestment and employee benefits	13	329					329
Equity offering	25	1,091					1,091
Common stock dividends, including equity units contract adjustment			(973)				(973)
Preferred and preference stock dividends			(14)				(14)
Other capital stock transactions, net			2				2
Balance December 31, 2001	**777**	**$6,217**	**$6,292**	**$(307)**	**$ 487**	**$ —**	**$12,689**
Net income			1,034				1,034
Other comprehensive income							
Foreign currency translation adjustments				(340)			(340)
Net unrealized gains on cash flow hedges[c]					37		37
Reclassification into earnings from cash flow hedges[d]					(102)		(102)
Minimum pension liability adjustment[e]						(484)	(484)
Total comprehensive income							145
Dividend reinvestment and employee benefits	13	342					342
Equity offering	55	975					975
Westcoast acquisition	50	1,702					1,702
Common stock dividends, including equity units contract adjustment			(905)				(905)
Preferred and preference stock dividends			(13)				(13)
Other capital stock transactions, net			9				9
Balance December 31, 2002	**895**	**$9,236**	**$6,417**	**$(647)**	**$ 422**	**$(484)**	**$14,944**
Net loss			(1,323)				(1,323)
Other comprehensive loss							
Foreign currency translation adjustments[b]				962			962
Net unrealized gains on cash flow hedges[c]					116		116
Reclassification into earnings from cash flow hedges[d]					(240)		(240)
Minimum pension liability adjustment[e]						40	40
Total comprehensive loss							(445)
Dividend reinvestment and employee benefits	16	283	(6)				277
Common stock dividends, including equity units contract adjustment			(993)				(993)
Preferred and preference stock dividends			(15)				(15)
Other capital stock transactions, net			(20)				(20)
Balance December 31, 2003	**911**	**$9,519**	**$4,060**	**$ 315**	**$ 298**	**$(444)**	**$13,748**

[a] Cumulative change in accounting principle, net of $573 tax benefit in 2001.

[b] Foreign currency translation adjustments, net of $114 million tax benefit in 2003.

[c] Net unrealized gains on cash flow hedges, net of $49 tax expense in 2003, $72 tax expense in 2002 and $748 tax expense in 2001.

[d] Reclassification into earnings from cash flow hedges, net of $130 tax benefit in 2003, $94 tax benefit in 2002 and $116 tax expense in 2001.

[e] Minimum pension liability adjustment, net of $27 tax expense in 2003 and $309 tax benefit in 2002.

Non-GAAP Financial Measures

(Loss) earnings before interest and taxes from continuing operations and ongoing (loss) earnings per share are non-GAAP (generally accepted accounting principles) financial measures as defined by the Securities and Exchange Commission under Regulation G.

(Loss) earnings before interest and taxes from continuing operations is one of the measures used by management to assess consolidated performance for continuing operations. It represents the combination of operating (loss) income, and other income and expenses as presented on the Consolidated Statements of Operations, and it excludes results and impacts of discontinued operations. Additionally, management believes its investors use (loss) earnings before interest and taxes from continuing operations as a supplemental measure to evaluate the company's consolidated results from continuing operations.

The company's management uses ongoing (loss) earnings per share, which represents net income adjusted for special items, as one of the measures to evaluate operations of the company. Special items represent certain charges or gains which management believes are not representative of the ongoing operations of the company. Management believes that the presentation and use of ongoing (loss) earnings per share provide useful information to investors, allowing them to more accurately compare the company's ongoing performance across all periods presented.

The following is a reconciliation of ongoing (loss) earnings per share to GAAP reported basic (loss) earnings per share for 2003 and 2002:

2003	Pre-tax Amount	Tax Effect	Full-year EPS
Earnings per share, ongoing			**$1.28**
DENA plant impairments and DETM charges	$(2,826)	$1,046	(1.97)
DENA redesignation of hedging contracts to mark-to-market	(262)	97	(0.18)
Charges and impairments for Australia and Europe	(292)	69	(0.25)
Cumulative effect of accounting changes	(256)	94	(0.18)
DENA goodwill write-off	(254)	90	(0.18)
Severance and related charges	(153)	55	(0.11)
Net gain on asset sales	185	(66)	0.13
DEI reserve and charges for environmental settlements in Brazil	(26)	10	(0.02)
Write-off of risk management system	(51)	19	(0.04)
Settlement with the South Carolina Public Service Commission	(46)	18	(0.03)
Settlement with the Commodity Futures Trading Commission	(17)	—	(0.02)
Tax benefit on 2002 impairment of goodwill at DEI for European gas trading	—	52	0.06
Tax adjustments	—	23	0.03
			(2.76)
Earnings per share, as reported			**$(1.48)**

2002	Pre-tax Amount	Tax Effect	Full-year EPS
Earnings per share, ongoing			**$1.88**
Impairment of goodwill at DEI for European gas trading	$(194)	$ —	(0.22)
Expenses at Franchised Electric associated with December 2002 ice storm	(89)	35	(0.06)
Severance charges associated with workforce reduction	(103)	40	(0.08)
Partial impairment of a merchant plant as a result of current market outlook	(31)	9	(0.04)
Asset impairments at Field Services	(28)	10	(0.02)
Termination of certain turbines on order, plus write-down of other uninstalled turbines	(163)	59	(0.13)
Write-off of site development costs, primarily in California and Brazil	(80)	30	(0.06)
Information technology system write-off at DENA	(24)	9	(0.02)
Demobilization costs at DENA	(22)	8	(0.02)
Settlement with North Carolina Utility Commission and Public Service Commission of South Carolina	(19)	7	(0.01)
			(0.66)
Earnings per share, as reported			**$1.22**

LEADERSHIP

Executive Committee

Duke Energy's Executive Committee is responsible for driving a strategy that optimizes shareholder value by providing a stable platform for growth and continued profitability. This group develops corporate strategy, allocates capital, outlines enterprise goals, implements Board direction, and in general leads the enterprise.

Paul M. Anderson
Chairman of the Board and Chief Executive Officer

Anderson has lead responsibility for positioning Duke Energy as a company that achieves superior results, optimizing the focus of the entire organization, improving execution and ensuring clear accountability. He chairs the Executive Committee and the Expanded Executive Committee.

Fred J. Fowler
President and Chief Operating Officer

Fowler chairs Duke Energy's Operating Committee, with responsibility for the operational, commercial and financial results of the company's energy-related businesses.

David L. Hauser
Group Vice President and Chief Financial Officer

Hauser is responsible for treasury, accounting, tax and risk management. His duties include certifying financial statements and overseeing risk control policies and systems.

Jim W. Mogg
Group Vice President and
Chief Development Officer

Mogg oversees strategy and corporate transactions, corporate and human resources development, mergers and acquisitions, diversity and the company's real estate affiliate.

Richard J. Osborne
Group Vice President, Public and Regulatory Policy

Osborne has responsibility for Duke Energy's public policy agenda and relationships with regulators, legislators, communities and other key stakeholders.

Martha B. Wyrsch
Group Vice President, General Counsel
and Secretary

Wyrsch is responsible for the company's legal affairs, compliance activities and the office of Corporate Secretary, as well as audit, ethics, security, business continuity and insurance.

Gregory L. Ebel
Secretary to the Executive Committee •
Vice President, Investor and Shareholder Relations

Ebel is responsible for relationships and communication with the investment community, and for monitoring changes and trends in investment markets.

Expanded Executive Committee

The Expanded Executive Committee includes the Executive Committee members as well as the heads of the major business units and a business services unit. This group is responsible for corporate policies and programs that reach across the business units.

William H. Easter III
Chairman, President and
Chief Executive Officer,
Duke Energy Field Services

Easter leads the company's natural gas gathering and processing and natural gas liquids business.

Robert B. Evans
President,
Duke Energy Americas

Evans is responsible for Duke Energy's North American and Latin American wholesale energy generation business.

A.R. Mullinax
Group Vice President,
Duke Energy Business Services

Mullinax directs global sourcing and logistics, information technology services, corporate real estate services and human resources services.

Greg Ebel, Ruth Shaw, David Hauser and (seated) Bobby Evans

Fred Fowler, Paul Anderson and Martha Wyrsch

A. R. Mullinax, Jim Mogg, Tom O'Connor, Bill Easter and (seated) Rich Osborne

Thomas C. O'Connor
President,
Duke Energy Gas Transmission

O'Connor leads Duke Energy's natural gas pipeline business in the United States and Canada.

Ruth G. Shaw
President,
Duke Power Company

Shaw oversees the electric utility that serves more than 2 million customers in North Carolina and South Carolina.

BOARD OF DIRECTORS

Paul M. Anderson, 58, Chairman of the Board and Chief Executive Officer, Duke Energy. Director since 2003. Paul Anderson rejoined Duke Energy in November, having served as its first President and Chief Operating Officer after the 1997 merger of Duke Power and PanEnergy.

G. Alex Bernhardt, Sr., 61, Chairman and Chief Executive Officer, Bernhardt Furniture Company. Audit Committee. Nuclear Oversight Committee. Director since 1991. Besides leading the family business in Lenoir, N.C., Bernhardt serves as a director of Cities in Schools and Smart Start, and on the Davidson College Board of Trustees.

Robert J. Brown, 69, Chairman and Chief Executive Officer, B&C Associates Inc. Audit Committee. Corporate Governance Committee. Director since 1994. Brown founded B&C Associates Inc., a marketing research and public relations firm in High Point, N.C. He serves on the Board of Trustees of the National Urban League.

William T. Esrey, 64, Chairman Emeritus, Sprint Corporation. Chairman, Japan Telecom. Audit Committee. Director since 1985. Esrey joined Sprint in 1980, and went on to serve as the company's Chief Financial Officer, President, Chief Executive Officer and Chairman. He joined Japan Telecom in 2003.

Ann Maynard Gray, 58, Former President, Diversified Publishing Group of ABC Inc. Corporate Governance Committee. Compensation Committee. Nuclear Oversight Committee. Finance and Risk Management Committee. Director since 1994. At American Broadcasting Companies Inc., Gray also held positions as Treasurer and Vice President of Planning. She currently serves as a trustee for J.P. Morgan funds.

George Dean Johnson, Jr., 61, Chief Executive Officer and Director, Extended Stay America Inc. Chairman, Finance and Risk Management Committee. Director since 1986. Johnson is also Chairman of Johnson Development Associates Inc. He served in the S.C. House of Representatives and as a director of the Federal Reserve Bank of Richmond.

Max Lennon, 63, President, Education and Research Services. Chairman, Audit Committee. Director since 1988. Lennon is a former president of Clemson University and Mars Hill College. He also served as President and Chief Executive Officer of Eastern Foods Inc.

Leo E. Linbeck, Jr., 69, Senior Chairman, Linbeck Corporation. Chairman, Compensation Committee. Finance and Risk Management Committee. Director since 1986. Linbeck Corp. is a group of two construction-related firms headquartered in Houston, Texas. Linbeck is past Chairman and director of the Federal Reserve Bank of Dallas.

James G. Martin, 68, Corporate Vice President, Carolinas HealthCare System. Chairman, Corporate Governance Committee. Compensation Committee. Nuclear Oversight Committee. Director since 1994. Martin was Governor of the state of North Carolina from 1985 to 1993, and previously was a U.S. Congressman. He is Chairman of the Global TransPark Foundation Inc.

Michael E.J. Phelps, 56, Chairman, Dornoch Capital Inc. Chairman, Duke Energy Canadian Advisory Council. Corporate Governance Committee. Finance and Risk Management Committee. Director since 2002. Phelps is former Chairman of the Board and Chief Executive Officer of Westcoast Energy Inc., acquired by Duke Energy in 2002.

James T. Rhodes, 62, Retired Chairman, President and Chief Executive Officer, Institute of Nuclear Power Operations. Chairman, Nuclear Oversight Committee. Audit Committee. Director since 2001. Rhodes was formerly President and Chief Executive Officer of Virginia Power. He currently serves on the Executive Committee of the Nuclear Energy Institute.

In October 2003, Rick Priory announced his retirement and stepped down as Chairman and CEO. Duke Energy thanks him for his leadership and contributions over his 27 years with the company, and wishes him well in his retirement.

INVESTOR INFORMATION

Annual Meeting
The 2004 Annual Meeting of Duke Energy Shareholders will be:
Date: Thursday, May 13, 2004
Time: 10 a.m.
Place: O.J. Miller Auditorium, Energy Center
526 South Church Street
Charlotte, NC 28202

Shareholder Services
Shareholders may call (800) 488-3853 or (704) 382-3853 with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services. Send e-mail requests to InvestDUK@duke-energy.com. Send written requests to:

Investor Relations
Duke Energy
P.O. Box 1005
Charlotte, NC 28201-1005

Stock Exchange Listing
Duke Energy's common stock and certain issues of first and refunding mortgage bonds, preferred securities and senior notes are listed on the New York Stock Exchange. The company's common stock trading symbol is DUK.

Web Site Address
www.duke-energy.com

InvestorDirect Choice Plan
The InvestorDirect Choice Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. Purchases may be made weekly. Bank drafts for monthly purchases, as well as a safekeeping option for depositing certificates into the plan, are available. The plan also provides for full reinvestment, direct deposit or cash payment of dividends.

Financial Publications
Duke Energy will furnish to any shareholder, without charge, printed copies of the 2003 Summary Annual Report and SEC Form 10-K. Those and other financial publications can also be found on our Web site.

Electronic Delivery
With a shareholder's consent, we can stop mailing paper copies of financial information and proxy statements. You can go to www.icsdelivery.com/duk to enroll in electronic delivery. You will need to provide your Social Security number or Tax I.D. number, your e-mail address, and a PIN number of your choice for electronic voting.

Duplicate Mailings
If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Call Investor Relations for instructions on eliminating duplications or combining your accounts.

Transfer Agent and Registrar
Duke Energy maintains shareholder records and acts as transfer agent and registrar for the company's common and preferred stock issues.

Dividend Payment
Duke Energy has paid quarterly cash dividends on its common stock for 77 consecutive years. Dividends on common and preferred stock are expected to be paid, subject to declaration by the Board of Directors, on March 16, June 16, Sept. 16 and Dec. 16, 2004.

Bond Trustee
If you have questions regarding your bond account, call (800) 275-2048, or write to:

JPMorgan Chase Bank
Institutional Trust Services
P.O. Box 2320
Dallas, TX 75221-2320

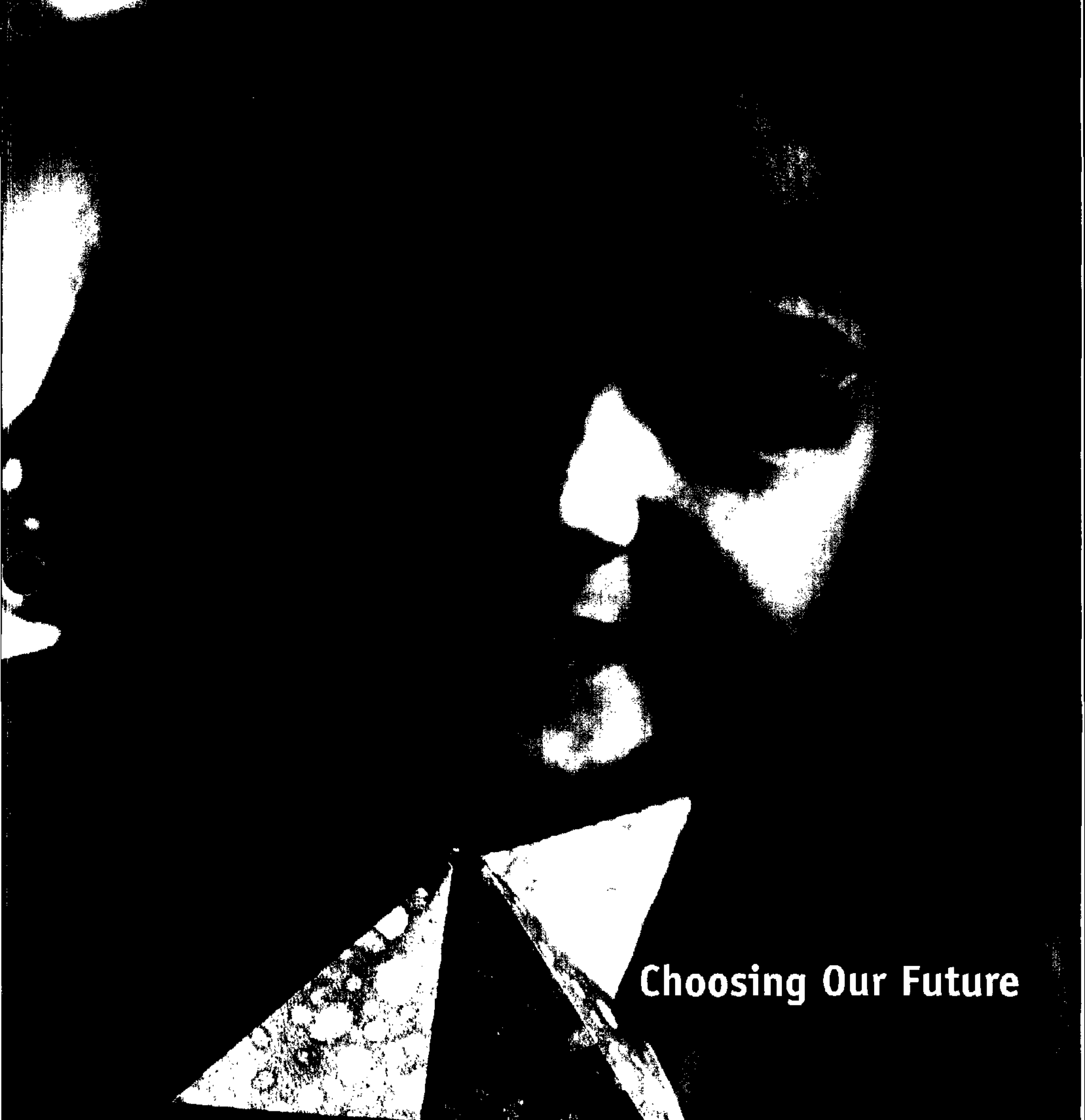
We welcome your opinion on Duke Energy's 2003 Annual Report. Please visit the Investors section of www.duke-energy.com, where you can view the online Annual Report and provide feedback on both the print and online versions. Or contact Investor Relations directly.

Duke Energy®

526 South Church Street
Charlotte, NC 28202-1802
704.594.6200
www.duke-energy.com

Heritage · Service · Vision
100 years
1904 - 2004

CINERGY CORP. 2003 ANNUAL REPORT



Choosing Our Future

CINERGY'S PURPOSE AND STRATEGY

Purpose:
We provide reliable, competitively priced energy and related services to the millions of people we serve, making their lives safer, healthier and more comfortable. We aspire to be the energy company preferred by each of our stakeholders — customers, employees, investors, suppliers and the communities we serve.

Strategy:
Balance, Improve, Grow — "Think BIG"
We strive to balance the needs of our stakeholders, improve everything we do and profitably grow the company.

CORPORATE PROFILE: LOW-RISK GROWTH PLATFORMS IN THE POWER AND GAS INDUSTRIES

	REGULATED	COMMERCIAL
BUSINESS DESCRIPTION	Regulated businesses consist of PSI's regulated generation and transmission and distribution operations, and CG&E's regulated electric and gas transmission and distribution systems. Regulated businesses plan, construct, operate and maintain Cinergy's transmission and distribution systems, and deliver gas and electric energy to consumers.	Commercial businesses manage, operate and/or maintain our generation, and the marketing and trading of energy commodities, primarily natural gas and electricity. The marketing and trading of energy commodities includes energy risk management activities and customized energy solutions.
NOTABLE STATISTICS	**Electric Operations** ■ Provides regulated transmission and distribution service to approximately 1.5 million customers ■ Serves a 25,000 square-mile service territory ■ Operates approximately 47,000 circuit miles of electric lines **Gas Operations** ■ Provides regulated transmission and distribution service to approximately 505,000 customers ■ Serves a 3,000 square-mile service territory ■ Operates approximately 13,400 miles of gas mains and service lines	■ Operates 13,331 megawatts of generating capacity ■ Owns and/or operates 19 cogeneration projects with over 1,200 megawatts of generating capacity ■ Marketed and traded 53.2 billion cubic feet per day of natural gas (physical and financial) in 2003 ■ Marketed and traded 147.5 million megawatt-hours of over-the-counter contracts for the purchase and sale of electricity in 2003 ■ Reported a $1.3 million average value at risk (VaR) associated with energy trading contracts traded for the 12 months ended December 31, 2003 (based on a 95 percent confidence interval, utilizing a one-day holding period)
PRODUCTS AND SERVICES	■ Electricity generation ■ Electricity transmission ■ Electricity distribution ■ Gas distribution	■ Electricity generation including operation of coal, gas, cogeneration and renewable power plants ■ Wholesale energy marketing, trading and risk management ■ Customized energy solutions

FINANCIAL HIGHLIGHTS: CONSISTENT PERFORMANCE

In millions, except as noted	2003	% Change	2002	2001
Operating Results				
Operating Revenues[1]	**$ 4,416**	8.8	$ 4,059	$ 3,950
Net Income	**$ 470**	30.2	$ 361	$ 442
Per Share of Common Stock				
Diluted Earnings	**$ 2.63**	23.5	$ 2.13	$ 2.75
Dividends Declared	**$ 1.84**	2.2	$ 1.80	$ 1.80
Book Value at Year-end	**$ 20.75**	6.2	$ 19.53	$ 18.45
Capitalization at Year-End				
Common Equity	**$ 3,701**	12.4	$ 3,293	$ 2,941
Preferred Trust Securities[2]	**—**	—	$ 308	$ 306
Preferred Stock	**$ 63**	—	$ 63	$ 63
Long-term Debt (including amounts due in one year)	**$ 4,971**	18.7	$ 4,188	$ 3,656
Other				
Total assets	**$14,119**	2.1	$13,832	$12,792
Employees (actual)	**7,693**	(1.7)	7,823	8,769

(1) Emerging Issues Task Force Issue 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities required that all gains and losses on energy trading derivatives be presented on a net basis beginning January 1, 2003. All periods presented have been reclassified for this change in accounting principle. This resulted in substantial reductions in reported Operating Revenues, Fuel and purchased and exchanged power expense, and Gas purchased expense. However, Operating Income and Net Income were not affected by this change.

(2) As a result of adopting Financial Accounting Standards Board Interpretation 46, we no longer consolidate the trust that held Company obligated, mandatorily redeemable, preferred trust securities of subsidiary, holding solely debt securities of the company. This resulted in the removal of these securities from our 2003 Balance Sheet and the addition to long-term debt of a $319 (net of discount) note payable that Cinergy Corp. owes the trust.

Why is Cinergy a good investment?

STRONG FINANCIAL FOUNDATION

- Strong investment-grade bond ratings
- Increasing cash flow from reduced capital requirements, price increases and productivity improvements
- Significant liquidity

LOW-RISK COMPANY IN THE POWER AND GAS INDUSTRIES

- One of the lowest cost and largest domestic non-nuclear generators of electricity
- Low-cost distribution assets and operations with high customer satisfaction ratings
- Diversified, balanced supply and demand portfolios in power and gas
- Constructive regulatory and legislative environments and outcomes

STRONG PLATFORM FOR BALANCED AND SUSTAINABLE EARNINGS GROWTH

- Approximately 90 percent of 2003 business contribution came from our regulated long-term power purchase agreements or from our regulated utilities
- The remaining contribution came from our commercial segments (wholesale power and gas, and cogeneration and energy services projects)

CONSISTENT PERFORMANCE THROUGH SUPERIOR EXECUTION

Earnings Growth

- 4 to 6 percent average long-term growth through balanced, low-risk platforms
- 2004 guidance range of $2.65 to $2.80 earnings per share

Dividend Growth

- Strong commitment to dividends
- Increases in each of the last two years; annual dividend of $1.88
- Target payout of 68 to 75 percent

Share Price Appreciation

- Consistent performance in all business cycles and in changing regulatory environments
- Superior shareholder returns (see table on page 8)

MANAGEMENT'S INTERESTS ALIGNED WITH SHAREHOLDERS' INTERESTS

- Almost 80 percent of CEO's and almost 60 percent of senior management team's total compensation is set by the board of directors and tied to corporate performance targets
- CEO is the 10th-largest shareholder; other executive officers, as a group, are the 12th-largest shareholder
- Instituted an "unusually tough ban" prohibiting officers and directors from selling shares acquired through option exercises until 90 days after leaving the Company[1]

[1] *The Wall Street Journal*, April 14, 2003

CORPORATE GOVERNANCE LEADER

- Institutional Shareholder Services Corporate Governance Quotient (CGQ):
  - — 98.1 percent in the S&P 500 Index
  - — 100.0 percent in the S&P Utilities Group
- Governance Metrics International (GMI):
  - — Overall Global Rating of 9 out of 10
  - — Overall Home Market (industry) Rating of 9 out of 10
- The Corporate Library:
  - — Board Effectiveness Rating of B
  - — Investment Risk Rating of Low

(All as of March 8, 2004)

Highlights of 10-Year Accomplishments

Since the Merger of CG&E and PSI to Form Cinergy (1994 - 2004)

1. Total Shareholder Return (TSR) of 191 percent (October 24, 1994 to December 31, 2003) has outpaced major utility and stock indices.

2. CG&E, ULH&P and PSI continue to have some of the lowest rates in Ohio, Kentucky and Indiana: adjusted for inflation, rates are essentially the same as they were in 1994.

3. Ranks second in the Midwest for residential and mid-sized business customer satisfaction as measured by a well-known independent customer satisfaction index.

4. National leader for low-cost, efficient operations of electric and gas utilities, power generation fleet and for reducing emissions.

5. Invested more than $1.7 billion since 1990 to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_x), reducing those emission rates by 50 percent and 45 percent, respectively.

6. First utility to announce its voluntary greenhouse gas (CO_2) reduction goal and has become a national leader in the energy and environmental policy debate.

7. Expanded successful new growth businesses in wholesale power and natural gas marketing, cogeneration and energy services.

8. A corporate governance leader in the S&P 500 and the top-ranked electric utility in the S&P Electric indices.

9. Named by *Working Mother* magazine as one of the 100 Best Companies for Working Mothers for seven consecutive years (2003).

10. Named to the Dow Jones Sustainability Indexes in 2003 as the most sustainable electric utility in the U.S. and second in the world.

JELANI YOUNG
Linda's 10-year-old son

LINDA YOUNG
Production Staff Clerk, Logistics & Operations

CHOOSING OUR FUTURE:

The Key Issues We Face

We've featured some of our employees' children and grandchildren in this year's report because they most tangibly remind us of why long-term sustainability is so important. When we deliver reliable, competitively priced energy to our customers, when we support and give back to our communities, and when we reduce our impact on the environment, we act as stewards of their future.

» The Future of Energy and Environmental Policy

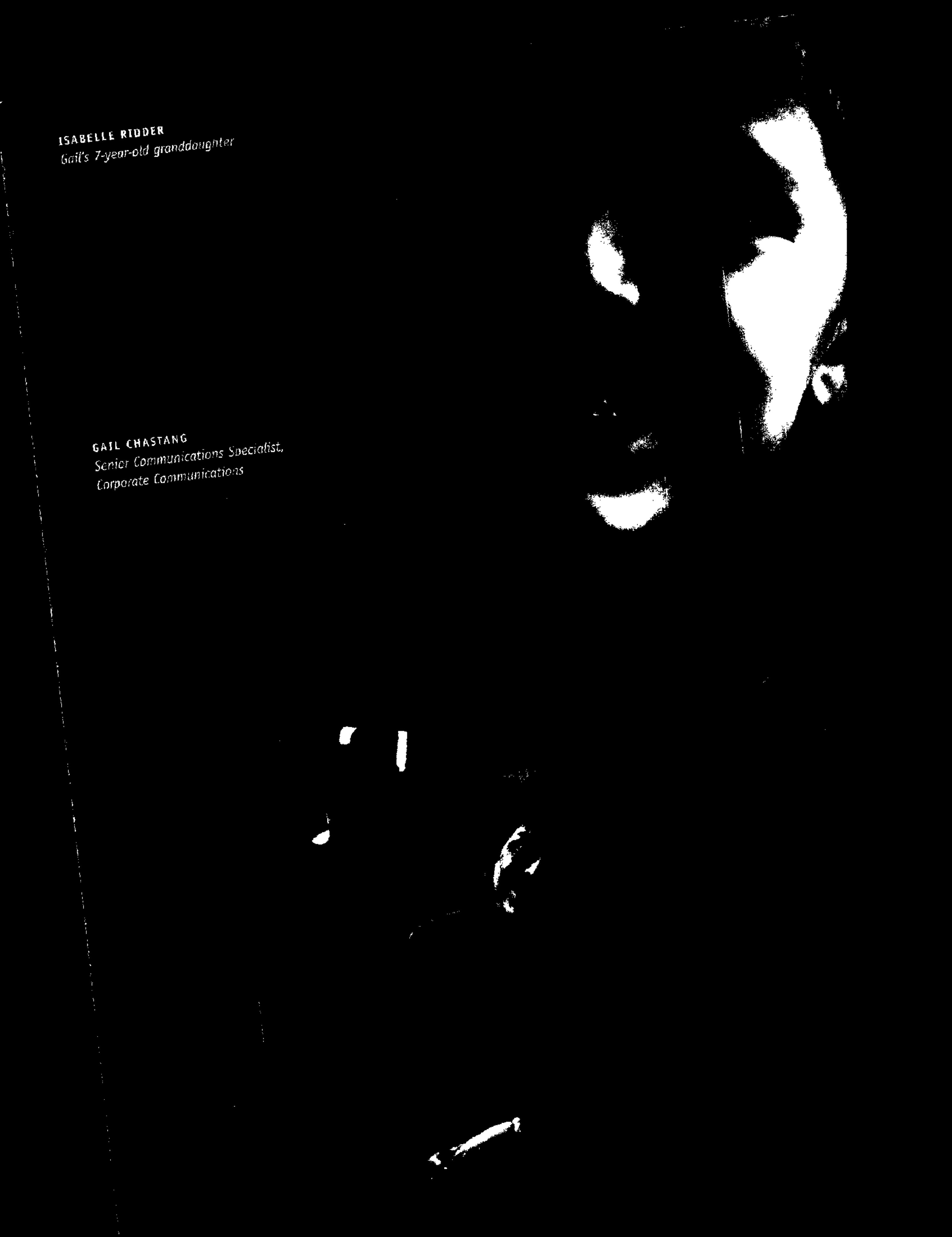
» The Future of Coal

» The Future of Natural Gas

» The Future of the Grid

LINDA YOUNG
ON CHOOSING
OUR FUTURE...

"As a parent, when I think about choosing my future, I think of 'home [illegible] My children enjoy the conveniences of many appliances and gadgets [illegible] take for granted. I hope when they grow older, get married and have [illegible] they will have the same comfort of a warm home and the conveniences [illegible] utility company. We want our children to think of their home and [illegible] havens and Cinergy helps provide that. I realize that nothing in life is [illegible] but knowing that I work for a company that strives to provide the best [illegible] customers is something to look forward to every day. When I made the [illegible] future and my family, I chose Cinergy."



ISABELLE RIDDER
Gail's 7-year-old granddaughter

GAIL CHASTANG
Senior Communications Specialist,
Corporate Communications

THE FUTURE OF ENERGY AND ENVIRONMENTAL POLICY:

Advancing Energy and Environmental Policy

The U.S. power industry is regulated by a diverse mix of state and federal laws and rules. In the past decade, important changes at the state and federal levels have spurred the development of wholesale power markets. In these markets, electricity prices are set by the laws of supply and demand, not primarily by regulators. Today, federal action is needed to support the full functioning of these markets. This will ensure that customers have reliable and low-cost energy, investors have a fair return on prudently invested capital and our nation has cleaner air from the more efficient use of our valuable energy resources.

» National Energy Policy Needed

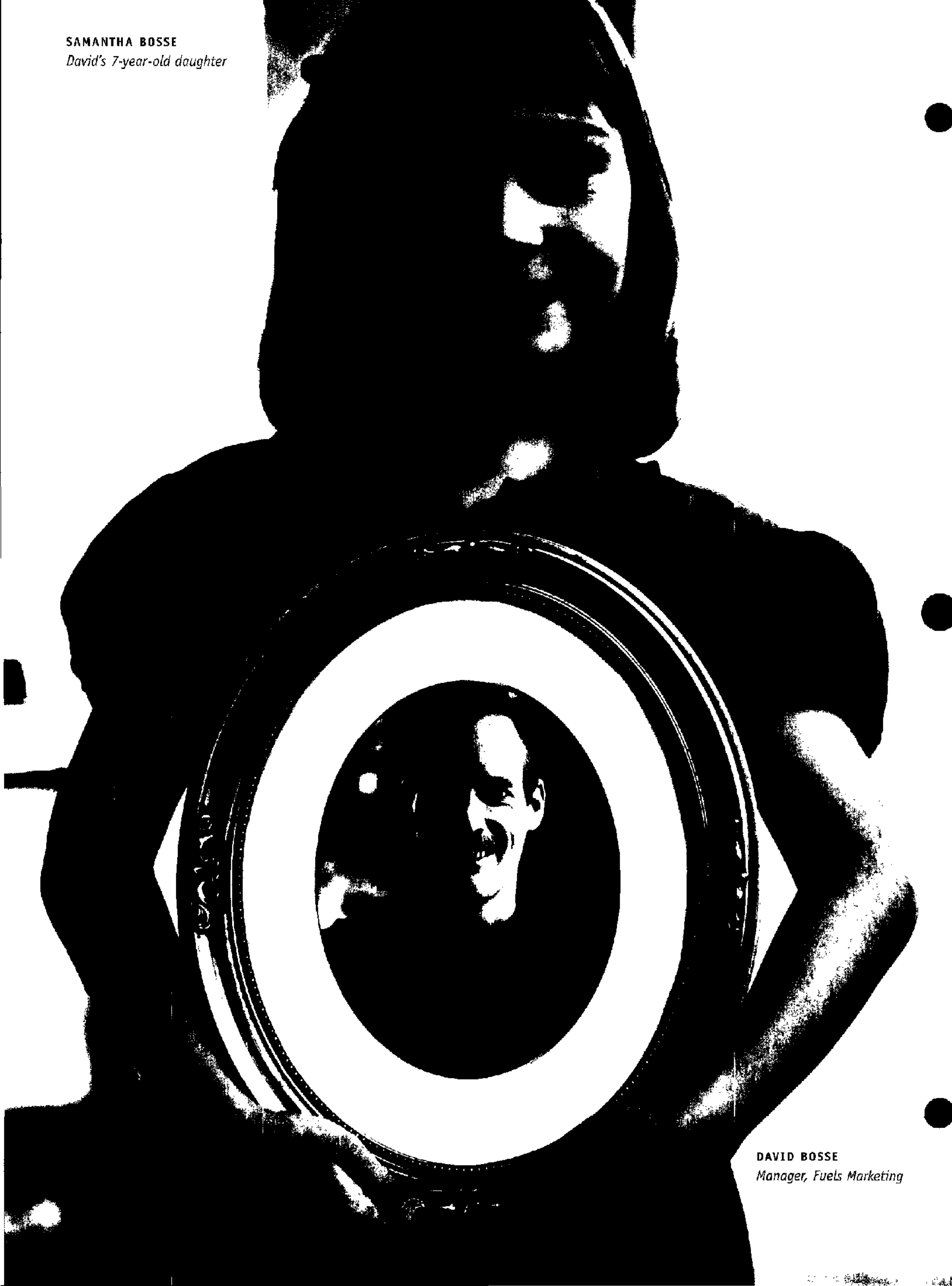
» Comprehensive Environmental Legislation is Key

» Policy Leadership with a "No Surprises" Approach

GAIL CHASTANG ON THE FUTURE OF ENERGY AND ENVIRONMENTAL POLICY...

"As a parent and grandparent, I believe that we need to move the U.S. closer to a balanced, long-term energy strategy that will guarantee affordable and reliable energy in our future. We need to become less dependent on foreign energy sources and continue to promote the use of renewable energy and clean coal technologies. I want to know that my daughters and granddaughter will have low-cost, reliable electricity to their homes. We must do whatever we can to preserve America's natural resources and environmental integrity."

SAMANTHA BOSSE
David's 7-year-old daughter



DAVID BOSSE
Manager, Fuels Marketing

THE FUTURE OF COAL:

National and Economic Security from Coal

The U.S. enjoys a 250-year supply of coal for electric power generation. This vast domestic energy resource is found predominantly in the western Rockies, the Midwest and in the Appalachian mountains. Coal helps ensure our national and economic security by reducing our reliance on imported oil and natural gas. New technologies have the potential to significantly reduce emissions from coal-fired plants and enhance its utility as our fundamental energy source.

» A Primary Source for Power Generation

» Cleaner Air with New Coal-Burning Technology

» Affordable, Reliable Supplies of Electricity from Coal

DAVID BOSSE
ON THE FUTURE OF COAL...

"Parents always want more for their children than they had. Low-cost energy from coal has been the fuel of our nation's economy and has helped us achieve the way of life we enjoy today. To ensure that our children have an even better quality of life, we must find innovative ways to use coal as a low-cost energy resource while reducing its impact on the environment. I'm proud that Cinergy is at the forefront of these efforts."

KAILAS MENON
Rajani's 7-year-old son

RAJANI MENON
Manager, Strategic Planning

THE FUTURE OF NATURAL GAS:

Developing Wholesale Natural Gas Markets

Since 2000, natural gas prices have fluctuated between $2.00 and $10.00 per million Btu. This unprecedented [illegible] volatility is having more impact on energy pricing and [illegible] economy than at any other time in history. The use of [illegible] gas to generate electricity is expected to double by 20[illegible] And while natural gas currently accounts for only [illegible] of U.S. electric generation, its importance as a [illegible] fuel for power plants makes it a highly desired f[illegible]

» "The Fuel at the Margin"

» New Market Opportunities

» Cinergy: Uniquely Positioned for Wholesale Gas Market Growth

» Fuel Diversity and Conservation

RAJANI MENON
ON THE FUTURE
OF NATURAL GAS...

"As a parent, I depend on gas to heat my home and cook meals for [illegible] gas industry faces new challenges such as dwindling reserves and f[illegible] focus is on making sure that my family can continue to use gas as a[illegible] at an affordable price. I hope that Cinergy can continue to develop [illegible] energy markets that will make the best use of this valuable resource."

DANIELLE SCHRADER
Steve's 8-year-old daughter

STEVE SCHRADER
Vice President and Chief Financial Officer, Regulated Businesses

THE FUTURE OF THE GRID:

Investing in the Grid — Our Nation's Electric [illegible] Superhighway

In the contiguous 48 states, electricity moves from [illegible] power plants to local distribution stations [illegible] of high-voltage transmission lines. Originally [illegible] the needs of customers in clearly defined [illegible] the transmission grid now also serves as a [illegible] for thousands of hourly wholesale power [illegible] result, the reliability of the grid to deliver [illegible] it is needed is becoming increasingly [illegible] policies change, extreme congestion and [illegible] will lead to further instability and higher [illegible]

» Reliability at Risk

» Investing in New Grid Capacity

» Long Lead Times for New Transmission Lines

» Cinergy: A Leader in Transmission Policy

STEVE SCHRADER ON THE FUTURE OF THE GRID...

"As a parent, I believe the analogy of the electric grid as a [illegible] Just as I expect adequate roads so my family can travel [illegible] to continue to provide the comforts of home. Although I [illegible] California if I like, most of my travel is still local, so I [illegible] the best. I hope our government can develop an electric grid [illegible] utilities to upgrade our electric grid. 'Road closed' does not [illegible]

BOARD OF DIRECTORS

JAMES E. ROGERS, *56, is chairman, president and CEO of Cinergy Corp. He has been a director since 1993 and chairs the Executive Committee.*

MICHAEL G. BROWNING, *57, has been a Cinergy director since 1994 and a director of PSI since 1990. He has served as chair of the Compensation Committee since 1999 and is also a member of the Audit, Corporate Governance and Executive Committees. Mr. Browning is chairman and president of Browning Investments Inc., Indianapolis, Ind.*

PHILLIP R. COX, *57, has been a Cinergy director since 1994 and a director of CG&E from 1994 to 1995. He has served as Public Policy Committee chair since May 2002 and is also a member of the Corporate Governance Committee. Mr. Cox is president and chief executive officer of Cox Financial Corp., Cincinnati, Ohio.*

GEORGE C. JUILFS, *64, has been a Cinergy director since 1994 and a director of CG&E from 1980 to 1995. He serves on the Compensation and Public Policy Committees. He is also a director of Cinergy Foundation. Mr. Juilfs is chairman and CEO of SENCORP, Newport, Ky.*

THOMAS E. PETRY, *64, has been a Cinergy director since 1994 and a director of CG&E from 1986 to 1995. He serves on the Compensation and Executive Committees. Mr. Petry served as chairman of the board and chief executive officer of Eagle-Picher Industries, Inc.*

PHILIP R. SHARP, *61, has been a Cinergy director since 1995 and serves on the Audit and Public Policy Committees. He is also a director of Cinergy Foundation. Mr. Sharp is a former member of the U.S. House of Representatives representing Indiana's 2nd Congressional District from 1975-1995.*

JOHN J. (JACK) SCHIFF JR., *60, has been a Cinergy director since 1994 and a CG&E director from 1986 to 1995. He serves on the Audit and Compensation Committees. Mr. Schiff is the chairman and CEO of Cincinnati Financial Corporation and The Cincinnati Insurance Company, Cincinnati, Ohio.*

MARY L. SCHAPIRO, *48, has been a Cinergy director since 1999 and was elected chair of the Audit Committee in May 2002. She also serves on the Public Policy Committee and is a director of Cinergy Foundation. Ms. Shapiro is Vice Chairman of NASD, Washington, D.C.*

DUDLEY S. TAFT, *63, has been a Cinergy director since 1994 and served as a director of CG&E from 1985 to 1995. He has served as chair of the Corporate Governance Committee since 1994. He is also a member of the Executive Committee. Mr. Taft is president of Taft Broadcasting Co., Cincinnati, Ohio.*

OFFICERS

JAMES E. ROGERS
Chairman, President and Chief Executive Officer

WENDY L. AUMILLER
Treasurer

JOHN BRYANT
Vice President of Cinergy and President of Cinergy Global Resources

MICHAEL J. CYRUS
Executive Vice President of Cinergy and Chief Executive Officer of the Commercial Business Unit

R. FOSTER DUNCAN
Executive Vice President and Chief Financial Officer

DOUGLAS F. ESAMANN
President, PSI Energy, Inc.

GREGORY C. FICKE
President, CG&E

BENNETT L. GAINES
Vice President and Chief Technology Officer

LYNN J. GOOD
Vice President and Controller

WILLIAM J. GREALIS
Executive Vice President

J. JOSEPH HALE, JR.
Vice President of Corporate Communications and President, Cinergy Foundation

M. STEPHEN HARKNESS
Vice President of Cinergy and President, Energy Services

JULIA S. JANSON
Corporate Secretary

MARC E. MANLY
Executive Vice President and Chief Legal Officer

THEODORE R. MURPHY II
Senior Vice President and Chief Risk Officer

FREDERICK J. NEWTON III
Executive Vice President and Chief Administrative Officer

RONALD R. REISING
Vice President, Finance

BERNARD F. ROBERTS
Vice President, Compliance

JAMES L. TURNER
Executive Vice President of Cinergy Corp. and Chief Executive Officer of the Regulated Businesses Business Unit

TIMOTHY J. VERHAGEN
Vice President of Human Resources

Financial Section

FINANCIAL TABLE OF CONTENTS

In this report Cinergy (which includes Cinergy Corp. and all of our regulated and non-regulated subsidiaries) is, at times, referred to in the first person as "we", "our", or "us".

Cautionary Statements Regarding Forward-Looking Information

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as "anticipate", "believe", "intend", "estimate", "expect", "continue", "should", "could", "may", "plan", "project", "predict", "will", and similar expressions.

Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- Factors affecting operations, such as:
  - (1) unanticipated weather conditions;
  - (2) unscheduled generation outages;
  - (3) unusual maintenance or repairs;
  - (4) unanticipated changes in costs;
  - (5) environmental incidents, including costs of compliance with existing and future environmental requirements; and
  - (6) electric transmission or gas pipeline system constraints.
- Legislative and regulatory initiatives.
- Additional competition in electric or gas markets and continued industry consolidation.
- Financial or regulatory accounting principles.
- Political, legal, and economic conditions and developments in the countries in which we have a presence.
- Changing market conditions and other factors related to physical energy and financial trading activities.
- The performance of projects undertaken by our non-regulated businesses and the success of efforts to invest in and develop new opportunities.
- Availability of, or cost of, capital.
- Employee workforce factors.
- Delays and other obstacles associated with mergers, acquisitions, and investments in joint ventures.
- Costs and effects of legal and administrative proceedings, settlements, investigations, and claims. Examples can be found in Note 11 of the Notes to Financial Statements.

We undertake no obligation to update the information contained herein.

The following discussion should be read in conjunction with the accompanying consolidated financial statements and related notes included elsewhere in this report. In addition, the results discussed elsewhere in this report are not necessarily indicative of the results to be expected in any future periods.

Introduction

In the Review of Financial Condition and Results of Operations, we explain our general operating environment, as well as our liquidity, capital resources, and results of operations. Specifically, we discuss the following:

- factors affecting current and future operations;
- potential sources of cash for future capital expenditures;
- why revenues and expenses changed from period to period; and
- how the above items affect our overall financial condition.

Organization

Cinergy Corp., a Delaware corporation organized in 1993, owns all outstanding common stock of The Cincinnati Gas & Electric Company (CG&E) and PSI Energy, Inc. (PSI), both of which are public utilities. As a result of this ownership, we are considered a utility holding company. Because we are a holding company with material utility subsidiaries operating in multiple states, we are registered with and are subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935, as amended (PUHCA). Our other principal subsidiaries are:

- Cinergy Services, Inc. (Services);
- Cinergy Investments, Inc. (Investments); and
- Cinergy Wholesale Energy, Inc. (Wholesale Energy).

CG&E, an Ohio corporation organized in 1837, is a combination electric and gas public utility company that provides service in the southwestern portion of Ohio and, through its subsidiaries, in nearby areas of Kentucky and Indiana. CG&E is responsible for the majority of our power marketing and trading activity. CG&E's principal subsidiary, The Union Light, Heat and Power Company (ULH&P), is a Kentucky corporation organized in 1901, that provides electric and gas service in northern Kentucky. CG&E's other subsidiaries are insignificant to its results of operations.

In 2001, CG&E began a transition to electric deregulation and customer choice. Currently, the competitive retail electric market in Ohio is in the development stage. CG&E is recovering its Public Utilities Commission of Ohio (PUCO) approved costs and retail electric rates are frozen during this market development period. In January 2003, CG&E filed an application with the PUCO for approval of a methodology to establish how market-based rates for non-residential customers will be determined when the market development period ends. In December 2003, the PUCO requested that CG&E propose a rate stabilization plan. In January 2004, CG&E complied with the PUCO request and filed an electric reliability and rate stabilization plan. See Retail Market Developments for a discussion of key elements of Ohio deregulation.

PSI, an Indiana corporation organized in 1942, is a vertically integrated and regulated electric utility that provides service in north central, central, and southern Indiana.

The following table presents further information related to the operations of our domestic utility companies (our operating companies):

PRINCIPAL LINE(S) OF BUSINESS
CG&E and subsidiaries
• Generation, transmission, distribution, and sale of electricity
• Sale and/or transportation of natural gas
• Electric commodity marketing and trading operations
PSI
• Generation, transmission, distribution, and sale of electricity

Services is a service company that provides our subsidiaries with a variety of centralized administrative, management, and support services. Investments holds most of our domestic non-regulated, energy-related businesses and investments, including natural gas marketing and trading operations.

Wholesale Energy, through a wholly-owned subsidiary, Cinergy Power Generation Services, LLC (Generation Services), provides electric production-related construction, operation, and maintenance services to certain affiliates and non-affiliated third parties.

We conduct operations through our subsidiaries and manage through the following three reportable segments:

- Commercial Business Unit (Commercial), formerly named the Energy Merchant Business Unit;
- Regulated Businesses Business Unit (Regulated Businesses); and
- Power Technology and Infrastructure Services Business Unit (Power Technology).

See Note 15 of the Notes to Financial Statements for financial information by reportable segment.

Liquidity and Capital Resources

COMPARATIVE CASH FLOW ANALYSIS FROM CONTINUING OPERATIONS

Operating Activities from Continuing Operations

Our cash flows provided from operating activities from continuing operations were $946 million, $956 million, and $724 million for the years ended December 31, 2003, 2002, and 2001, respectively. The tariff-based gross margins of our operating companies continue to be the principal source of cash from operating activities. The diversified retail customer mix of residential, commercial, and industrial classes and a commodity mix of gas and electric services provide a reasonably predictable gross cash flow.

For the year ended December 31, 2002, our net cash provided by operating activities from continuing operations increased, as compared to 2001, primarily due to increases in net income after adjusting for non-cash items such as depreciation; favorable working capital fluctuations; and deferred income taxes. The increase in deferred income taxes, in part, reflects a change in accounting methodology for tax purposes related to capitalized costs, which increased current tax deductions. Current tax obligations were also reduced by increases in tax credits associated with the production and sale of synthetic fuel.

Financing Activities from Continuing Operations

Our cash flows used in financing activities from continuing operations were $245 million for the year ended December 31, 2003, compared to cash inflows of $43 million and $828 million for the years ended December 31, 2002 and 2001, respectively. For the year ended December 31, 2003, our net cash used in financing activities from continuing operations increased, as compared to 2002, primarily due to increases in redemptions of long-term debt and the establishment of funds on deposit from the issuance of debt securities.

For the year ended December 31, 2002, our net cash provided by financing activities from continuing operations decreased, as compared to 2001. This decrease was primarily due to the net proceeds received in 2001 from the issuance of *Preferred Trust Securities* and from new debt issuances, which were used to fund the purchase of new peaking generation facilities and environmental compliance expenditures. The repayment of both long-term and short-term debt reduced cash proceeds recognized in 2002 from the issuances of common stock and new long-term debt.

Investing Activities from Continuing Operations

Our cash flows used in investing activities were $732 million, $886 million, and $1.5 billion for the years ended December 31, 2003, 2002, and 2001, respectively. For the year ended December 31, 2003, our net cash used in investing activities from continuing operations decreased as compared to 2002, primarily due to decreases in capital expenditures related to environmental compliance programs, and other energy-related investments. We also purchased a synthetic fuel production facility during 2002.

For the year ended December 31, 2002, our net cash used in investing activities from continuing operations decreased, as compared to 2001. This decrease was primarily the result of our 2001 acquisition of peaking generation facilities, increased capital expenditures related to environmental compliance programs, and other non-core investments.

CAPITAL REQUIREMENTS

Actual construction and other committed expenditures (including capitalized financing costs) for 2003 were $800 million. Our forecasted construction and other committed expenditures (in nominal dollars) are $756 million for 2004 and $4.1 billion for the five-year period 2004-2008.

This forecast includes an estimate of expenditures to comply with draft regulations requiring reduction in mercury, nitrogen oxide (NO_X), and sulfur dioxide (SO_2) emissions. In 2003, we spent $160 million for NO_X and other environmental compliance projects. Forecasted expenditures for environmental compliance projects (in nominal dollars) are approximately $168 million for 2004 and $1.2 billion for the 2004-2008 period. Approximately 75 percent of these estimated environmental costs would be incurred at regulated coal-fired plants. See Air Toxics and Ambient Air Standards for further information.

Environmental Commitment and Contingency Issues

Manufactured Gas Plant (MGP) Sites In November 1998, PSI entered into a Site Participation and Cost Sharing Agreement with Northern Indiana Public Service Company and Indiana Gas Company, Inc. related to contamination at MGP sites, which PSI or its predecessors previously owned. Until investigation and remediation activities have been completed on the sites, we are unable to reasonably estimate the total cost and impact on our financial position or results of operations. In relation to the MGP claims, PSI also filed suit against its general liability insurance carriers. Subsequently, PSI sought a declaratory judgment to obligate its insurance carriers to (1) defend MGP claims against PSI, or (2) pay PSI's costs of defense and compensate PSI for its costs of investigating, preventing, mitigating, and remediating damage to property and paying claims related to MGP sites. At the present time, PSI cannot predict the outcome of this litigation. See Note 11(A)*(iii)* of the Notes to Financial Statements for further information on MGP sites.

Regional Haze The United States (U.S.) Environmental Protection Agency (EPA) published the final regional haze rule in July 1999. This rule established planning and emission reduction timelines for states to use to improve visibility in national parks throughout the U.S. The ultimate effect of the new regional haze rule could be requirements for (1) newer and cleaner technologies and additional controls on particulates emissions, and (2) reductions in SO_2 and NO_X emissions from utility sources. If more utility emissions reductions are required, the compliance cost could be significant. In August 1999, several industry groups (some of which we are a member) filed a challenge to the regional haze rules with the U.S. Circuit Court of Appeals for the District of Columbia (Court of Appeals). In May 2002, the Court of Appeals set aside a portion of the EPA's rule, holding that the rule improperly forced states to require emissions controls without adequate consideration of an individual source's impact on visibility impairment. We currently cannot predict the timing or outcome of the EPA's response to the Court of Appeals' ruling.

In July 2001, the EPA proposed guidance to implement portions of the regional haze rule. This guidance recommends that states require widespread installation of scrubbers to reduce SO_2 emissions. We currently cannot determine whether or how the EPA will modify the scope of this guidance, or whether the states in which we operate will adopt the EPA's proposed guidance.

Air Toxics and Ambient Air Standards In December 2003, the EPA issued draft regulations regarding required reductions in mercury emissions from coal-fired power plants. The draft regulations include two possible alternatives to address emission reductions. One alternative would include a cap and trade approach to mercury. The other would be a source specific reduction in emissions, without a cap and trade approach. The cap and trade approach would provide a longer compliance horizon and provide more flexible compliance options for coal-fired generators. The EPA is expected to issue final rules by December 2004.

In December 2003, the EPA also proposed Interstate Air Quality Rules that would require states to revise their State Implementation Plans to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards (NAAQS) for ozone and fine particulate matter. The proposed rule would establish a two-phase, regional cap and trade program for SO_2 and NO_X. The proposed rule would affect approximately 30 states, including Ohio, Indiana, and Kentucky. The proposed rule would require SO_2 emissions to be cut approximately 70 percent by 2015 and NO_X emissions to be cut approximately 65 percent by 2015. The EPA is expected to issue final rules by December 15, 2004.

We currently estimate costs associated with the cap and trade approach to mercury, SO_2 and NO_X emissions reductions to be approximately $1.2 billion over the next five years. These costs have been included in our forecasted capital expenditures discussed previously in Capital Requirements. Approximately 75 percent of these estimated environmental costs would be incurred at regulated coal-fired plants, for which recovery would be pursued in accordance with regulatory statutes governing environmental cost recovery. Costs associated with the source specific approach to mercury emissions reductions may be higher, depending on the type of program the EPA finalizes and the stringency and timing of the ultimate requirements. Due to these uncertainties, we are unable to predict the magnitude of those costs at this time.

In 1997, the EPA revised the NAAQS for ozone and fine particulate matter. The EPA is under a court-ordered deadline to make final state ozone non-attainment area designations by April 15, 2004, and fine particulate area designations by December 15, 2004. Several counties in which we operate have been tentatively designated (by their respective states) as being in non-attainment with the new ozone standard, and several are likely to be designated as non-attainment with the fine particulate standard. We cannot predict the timing or effect of the ozone non-attainment designations at this time.

Global Climate Change In September 2003, we announced an internal voluntary greenhouse gas (GHG) management goal to reduce our GHG emissions by 2010. We expect to spend $21 million between 2004 and 2010 on projects to reduce or offset our GHG emissions. Our goal is to support the President's voluntary initiative, to address shareholder interest in the issue, and to build internal expertise in GHG management and GHG markets.

Our plan for managing the potential risk and uncertainty of regulations relating to climate change includes the following:

- implementing an internal voluntary goal to reduce our GHG emissions five percent below our 2000 baseline emission levels by 2010 and maintaining those levels through 2012;
- measuring and inventorying company related sources of GHG emissions;
- identifying and pursuing cost-effective GHG emission reduction and offsetting activities;
- funding research of more efficient and alternative electric generating technologies;
- funding research to better understand the causes and consequences of climate change; and
- encouraging a global discussion of the issues and how best to manage them.

Asbestos Claims Litigation CG&E and PSI have been named as defendants or co-defendants in lawsuits related to asbestos at their electric generating stations. Currently, there are approximately 80 pending lawsuits. In these lawsuits, plaintiffs claim to have been exposed to asbestos-containing products in the course of their work at the CG&E and PSI generating stations. The plaintiffs further claim that as the property owner of the generating stations, CG&E and PSI, should be held liable for their injuries and illnesses based on an alleged duty to warn and protect them from any asbestos exposure. A majority of the lawsuits to date have been brought against PSI. The impact on CG&E's and PSI's financial position or results of operations of these cases to date has not been material. See Note 11(A)*(iv)* of the Notes to Financial Statements for a discussion of asbestos claims and related cases.

Pension and Other Postretirement Benefits

We maintain qualified defined benefit pension plans covering substantially all U.S. employees meeting certain minimum age and service requirements. Plan assets consist of investments in equity and debt securities. Funding for the qualified defined benefit pension plans is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended (ERISA). Although mitigated by strong performance in 2003, ongoing retiree payments and the decline in market value of the investment portfolio in 2002 have reduced assets held in trust to satisfy plan obligations. Additionally, decreases in long-term interest rates have had the effect of increasing the liability used for funding purposes. As a result of these events, our near term funding targets have increased substantially. We have adopted a five-year plan to reduce, or eliminate, the unfunded pension obligation initially measured as of January 1, 2003. This unfunded obligation will be recalculated as of January 1 of each year in the five-year plan. Such unfunded obligation was calculated as the difference between the liability determined actuarially on an ERISA basis and the market value of plan assets as of January 1, 2003. The liability used in this calculation is different than the pension liability calculated for accounting purposes reported on our Balance Sheets. Our minimum required contributions in calendar year 2003 were $11 million, as compared to $4 million in calendar year 2002. Our minimum required contributions in calendar year 2004 are expected to be approximately $16 million. Actual contributions during calendar year 2003 totaled $74 million reflecting additional discretionary contributions of $63 million under the aforementioned five-year plan. Should Cinergy continue funding under this five-year plan, discretionary contributions in addition to the minimum funding requirements are expected to be $90 million in 2004. We may consider making discretionary contributions in 2005 and future periods, however at this time, we are unable to determine the amount of those contributions. Estimated contributions fluctuate based on changes in market performance of plan assets and actuarial assumptions. Absent the occurrence of interim events that could materially impact these targets, we will update our expected target contributions annually as the actuarial funding valuations are completed and make decisions about future contributions at that time.

We sponsor non-qualified pension plans that cover officers, certain key employees, and non-employee directors. Our payments for these non-qualified pension plans are expected to be approximately $8 million in 2004.

We provide certain health care and life insurance benefits to retired U.S. employees and their eligible dependents. Our payments for these postretirement benefits in 2004 are expected to be approximately $27 million. See Note 9 of the Notes to Financial Statements for additional information about our pension and other postretirement benefit plans.

Long-term debt due within one year

Our *Long-term debt due within one year* increased $663 million from December 31, 2002 to December 31, 2003. The primary cause of the increase was the reclassification of our $200 million 6.125% Debentures due April 15, 2004 and $500 million 6.25% Debentures due September 1, 2004 from *Long-term debt* to *Long-term debt due within one year*.

As discussed in Note 4 of the Notes to Financial Statements, in September 2003, PSI issued $400 million principal amount of its 5.00% Debentures largely using the proceeds from this issuance for the early redemption of two subordinated promissory notes to us totaling $376 million. We plan to use the proceeds to partially fund the maturity of the 6.125% and 6.25% debentures discussed above. In the interim, we have used the proceeds to repay short-term indebtedness.

We plan to meet remaining future debt obligations from the issuance of debt and/or equity securities and internally-generated funds.

Other Investing Activities

Our ability to invest in growth initiatives is limited by certain legal and regulatory requirements, including the PUHCA. The PUHCA limits the types of non-utility businesses in which Cinergy and other registered holding companies under PUHCA can invest as well as the amount of capital that can be invested in permissible non-utility businesses. Also, the timing and amount of investments in the non-utility businesses is dependent on the development and favorable evaluations of opportunities. Under the PUHCA restrictions, we are allowed to invest or commit to invest in certain non-utility businesses, including:

Exempt Wholesale Generators (EWG) and Foreign Utility Companies (FUCO) An EWG is an entity, certified by the Federal Energy Regulatory Commission (FERC), devoted exclusively to owning and/or operating, and selling power from one or more electric generating facilities. An EWG whose generating facilities are located in the U.S. is limited to making only wholesale sales of electricity.

A FUCO is a company all of whose utility assets and operations are located outside the U.S. and which are used for the generation, transmission, or distribution of electric energy for sale at retail or wholesale, or the distribution of gas at retail. A FUCO may not derive any income, directly or indirectly, from the generation, transmission or distribution of electric energy for sale or the distribution of gas at retail within the U.S. An entity claiming status as a FUCO must provide notification thereof to the SEC under PUHCA.

We have been granted SEC authority under PUHCA to invest (including by way of guarantees) an aggregate amount in EWGs and FUCOs equal to the sum of (1) our average consolidated retained earnings from time to time plus (2) $2 billion. As of December 31, 2003, we had invested or committed to invest $0.8 billion in EWGs and FUCOs, leaving available investment capacity under the order of $2.7 billion.

Qualifying Facilities and Energy-Related Non-utility Entities SEC regulations under the PUHCA permit us and other registered holding companies to invest and/or guarantee an amount equal to 15 percent of consolidated capitalization (consolidated capitalization is the sum of *Notes payable and other short-term obligations*, *Long-term debt* (including amounts due within one year), *Preferred Trust Securities*, *Cumulative Preferred Stock of Subsidiaries*, and total *Common Stock Equity*) in domestic qualifying cogeneration and small power production plants (qualifying facilities) and certain other domestic energy-related non-utility entities. At December 31, 2003, we had invested and/or guaranteed approximately $0.9 billion of the $1.4 billion available.

Energy-Related Assets We have been granted SEC authority under PUHCA to invest up to $1 billion in non-utility Energy-Related Assets within the U.S., Canada, and Mexico. Energy-Related Assets include natural gas exploration, development, production, gathering, processing, storage and transportation facilities and equipment, liquid oil reserves and storage facilities, and associated assets, facilities and equipment, but exclude any assets, facilities or equipment that would cause the owner or operator thereof to be deemed a public utility company. As of December 31, 2003, we did not have any investments in these Energy-Related Assets.

Infrastructure Services Companies We have been granted SEC authority under PUHCA to invest up to $500 million in companies that derive or will derive substantially all of their operating revenues from the sale of Infrastructure Services including:

- Design, construction, retrofit and maintenance of utility transmission and distribution systems;
- Installation and maintenance of natural gas pipelines, water and sewer pipelines, and underground and overhead telecommunications networks; and
- Installation and servicing of meter reading devices and related communications networks, including fiber optic cable.

At December 31, 2003, we had invested approximately $26 million in these Infrastructure Services companies.

Contractual Cash Obligations

The following table presents our significant contractual cash obligations:

	Payments Due						
(in millions)	2004	2005	2006	2007	2008	There-after	Total
Capital leases	$ 5	$ 6	$ 6	$ 6	$ 8	$ 24	$ 55
Operating leases	41	33	26	21	13	37	171
Long-term debt (including amounts due within one year)	835	222(1)(2)	354	727	550	2,333	5,021
Fuel purchase contracts(3) (6)	671	569	471	465	336	1,374	3,886
Other commodity purchase contracts(4)	21	2	–	–	–	–	23
Qualified pension plans(5)	16	–	–	–	–	–	16
Total	$1,589	$832	$857	$1,219	$907	$3,768	$9,172

(1) Includes 6.50% Debentures due August 1, 2026, reflected as maturing in 2005, as the interest rate is due to reset on August 1, 2005.
(2) Includes 6.90% Debentures due June 1, 2025, reflected as maturing in 2005, as the debentures are putable to CG&E at the option of the holders on June 1, 2005.
(3) Some fuel purchase contracts contain price re-opener provisions that may be exercised upon mutual agreement of the parties or upon unilateral action by a party.
(4) Includes long term contracts accounted for on an accrual basis. See the Changes in Fair Value table in Market Risk Sensitive Instruments and Positions for disclosure of energy trading contracts that are accounted for at fair value.
(5) Represents only our minimum required contributions. Although not required, we intend to contribute an additional $90 million in 2004 to strengthen the funding status of the plan. Minimum required contributions for future periods are not yet known. See Pension and Other Postretirement Benefits for further details regarding potential future cash payments under our pension and other postretirement benefit plans.
(6) Subsequent to the year ended December 31, 2003, we executed fuel purchase contracts with aggregate contractual cash obligations of $33 million, $61 million, $46 million, and $48 million for 2004, 2005, 2006, and 2007, respectively.

Guarantees

We are subject to an SEC order under the PUHCA, which limits the amounts Cinergy Corp. can have outstanding under guarantees at any one time to $2 billion. As of December 31, 2003, we had $693 million outstanding under the guarantees issued, of which approximately 90 percent represents guarantees of obligations reflected on our Balance Sheets. The amount outstanding represents Cinergy Corp.'s guarantees of liabilities and commitments of its consolidated subsidiaries, unconsolidated subsidiaries, and joint ventures. See Note 11(C)*(vii)* of the Notes to Financial Statements for a discussion of guarantees in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* (Interpretation 45). Interpretation 45 requires disclosure of maximum potential liabilities for guarantees issued on behalf of unconsolidated subsidiaries and joint ventures and under indemnification clauses in various contracts. The Interpretation 45 disclosure differs from the PUHCA restrictions in that it requires a calculation of maximum potential liability, rather than actual amounts outstanding; it excludes guarantees issued on behalf of consolidated subsidiaries; and it includes potential liabilities under indemnification clauses.

Collateral Requirements

We have certain contracts in place, primarily with trading counterparties, that require the issuance of collateral in the event our debt ratings are downgraded below investment grade. Based upon our December 31, 2003 trading portfolio, if such an event were to occur, we would be required to issue up to approximately $73 million in collateral related to our gas and power trading operations.

CAPITAL RESOURCES

We meet current and future capital requirements through:

- internally generated funds;
- cash and cash equivalents on hand;
- issuance of debt and equity securities;
- bank financing under new and existing facilities; and
- monetization of assets.

We believe that we have adequate financial resources to meet our future needs.

Notes Payable and Other Short-term Obligations

We are required to secure authority to issue short-term debt from the SEC under the PUHCA and from the PUCO. The SEC under the PUHCA regulates the issuance of short-term debt by Cinergy Corp., PSI, and ULH&P. The PUCO has regulatory jurisdiction over the issuance of short-term debt by CG&E.

Our short-term regulatory authority at December 31, 2003, was as follows:

(in millions)	Authority	Outstanding
Cinergy Corp.	$5,000(1)	$146

(1) Cinergy Corp., under the PUHCA, was granted approval to increase total capitalization (excluding retained earnings and accumulated other comprehensive income (loss)), which may be any combination of debt and equity securities, by $5 billion. Outside this requirement, Cinergy Corp. is not subject to specific regulatory debt authorizations.

For the purposes of quantifying regulatory authority, short-term debt includes revolving credit borrowings, uncommitted credit line borrowings, and commercial paper.

Cinergy Corp.'s short-term borrowing consists primarily of unsecured revolving lines of credit and the sale of commercial paper. Cinergy Corp.'s $1 billion revolving credit facilities and $800 million commercial paper program also support the short-term borrowing needs of our operating companies. In addition, we maintain uncommitted lines of credit. These facilities are not firm sources of capital but rather informal agreements to lend money, subject to availability, with pricing determined at the time of advance.

A summary of our outstanding short-term borrowings, including variable rate pollution control notes is as follows:

	Short-term Borrowings December 31, 2003				
(in millions)	Established Lines	Outstanding	Unused	Standby Liquidity(3)	Available Revolving Lines of Credit
Cinergy Corp.					
Revolving lines	$1,000	$ –	$1,000	$159	$841
Uncommitted lines(1)	40	–	40		
Commercial paper(2)		146	654		
Operating companies					
Uncommitted lines(1)	75	–	75		
Pollution control notes		193			
Non-regulated subsidiaries					
Revolving lines	19	10	9		9
Short-term debt		2			
Total		$351			$850

(1) Outstanding amounts may be greater than established lines as uncommitted lenders are, at times, willing to loan funds in excess of the established lines.
(2) The commercial paper program is limited to $800 million and is supported by Cinergy Corp.'s revolving lines of credit.
(3) Standby liquidity is reserved against the revolving lines of credit to support the commercial paper program and outstanding letters of credit (currently $146 million and $13 million, respectively).

At December 31, 2003, Cinergy Corp. had $841 million remaining unused and available capacity relating to its $1 billion revolving credit facilities. These revolving credit facilities include the following:

(in millions)

Credit Facility	Expiration	Established Lines	Outstanding and Committed	Unused and Available
364-day senior revolving[1]	April 2004			
Direct borrowing		$	$ –	$
Commercial paper support			146	
Total 364-day facility		600	146	454
Three-year senior revolving[1]	May 2004			
Direct borrowing			–	
Commercial paper support			–	
Letter of credit support			13	
Total Three-year facility		400	13	387
Total Credit Facilities		$1,000	$159	$841

(1) Cinergy Corp. has historically followed the practice of renewing its credit facilities upon expiration.

In April 2003, Cinergy Corp. successfully placed a $600 million, 364-day senior unsecured revolving credit facility. This facility replaced the $600 million, 364-day facility that expired April 30, 2003.

In our credit facilities, Cinergy Corp. has covenanted to maintain:

- a consolidated net worth of $2 billion; and
- a ratio of consolidated indebtedness to consolidated total capitalization not in excess of 65 percent.

A breach of these covenants could result in the termination of the credit facilities and the acceleration of the related indebtedness. In addition to breaches of covenants, certain other events that could result in the termination of available credit and acceleration of the related indebtedness include:

- bankruptcy;
- defaults in the payment of other indebtedness; and
- judgments against the company that are not paid or insured.

The latter two events, however, are subject to dollar-based materiality thresholds.

As discussed in Note 1(Q)*(iv)* of the Notes to Financial Statements, long-term debt increased in 2003 resulting from the adoption of FASB Interpretation No. 46, *Consolidation of Variable Interest Entities* (Interpretation 46). The debt which was recorded as a result of this new accounting pronouncement did not cause Cinergy Corp. to be in breach of any covenants.

Variable Rate Pollution Control Notes

CG&E and PSI have issued certain variable rate pollution control notes (tax-exempt notes obtained to finance equipment or land development for pollution control purposes). Because the holders of these notes have the right to have their notes redeemed on a daily, weekly, or monthly basis, they are reflected in *Notes payable and other short-term obligations* on our Balance Sheets. At December 31, 2003, we had $192.6 million outstanding in variable rate pollution control notes, classified as short-term debt. Any short-term pollution control note borrowings outstanding do not reduce the unused and available short-term debt regulatory authority of our operating companies. See Note 6 of the Notes to Financial Statements for additional information regarding pollution control notes.

Operating Leases

We have entered into operating lease agreements for various facilities and properties such as computer, communication and transportation equipment, and office space. See Note 7(A) of the Notes to Financial Statements for additional information regarding operating leases.

Capital Leases

Our operating companies are able to enter into capital leases subject to the authorization limitations of the applicable state utility commissions. New financing authority is subject to the approval of the respective commissions. In May 2002, ULH&P received approval from the Kentucky Public Service Commission (KPSC) to enter into an additional $25 million of capital lease obligations for the period ending December 31, 2004. In June 2002, PSI received approval from the Indiana Utility Regulatory Commission (IURC) to enter into an additional $100 million of capital lease obligations for the period ending December 31, 2003. In January 2004, PSI filed a petition for an additional $100 million of capital lease obligations. In December 2002, CG&E received approval from the PUCO to enter into an additional $74 million of capital lease obligations for the period ending December 31, 2003. In January 2004, CG&E filed a petition for an extension of capital lease obligations. See Note 7(B) of the Notes to Financial Statements for additional information regarding capital leases.

Long-term Debt

We are required to secure authority to issue long-term debt from the SEC under the PUHCA and the state utility commissions of Ohio, Kentucky, and Indiana. The SEC under the PUHCA regulates the issuance of long-term debt by Cinergy Corp. The respective state utility commissions regulate the issuance of long-term debt by our operating companies.

A summary of our long-term debt authorizations at December 31, 2003, was as follows:

(in millions)	Authorized	Used	Available
Cinergy Corp.			
PUHCA total capitalization(1)	$5,000	$1,561	$3,439

(1) Cinergy Corp., under PUHCA, was granted approval to increase total capitalization (excluding retained earnings and accumulated other comprehensive income (loss)), which may be any combination of debt and equity securities, by $5 billion. Outside this requirement, Cinergy Corp. is not subject to specific regulatory debt authorizations.

Cinergy Corp. has an effective shelf registration statement with the SEC relating to the issuance of up to $750 million in any combination of common stock, preferred stock, stock purchase contracts or unsecured debt securities, of which approximately $574 million remains available for issuance. CG&E has an effective shelf registration statement with the SEC relating to the issuance of up to $500 million in any combination of unsecured debt securities, first mortgage bonds, or preferred stock, of which $100 million remains available for issuance. PSI has an effective shelf registration statement with the SEC relating to the issuance of up to $700 million in any combination of unsecured debt securities, first mortgage bonds, or preferred stock, of which $300 million remains available for issuance. In February 2004, CG&E and PSI filed with the SEC to increase the available capacity under their shelf registration statements to $800 million for each company. ULH&P has effective shelf registration statements with the SEC relating to the issuance of up to $50 million in unsecured debt securities and up to $40 million in first mortgage bonds, of which $30 million in unsecured debt securities and $20 million in first mortgage bonds remain available for issuance.

Off-Balance Sheet Arrangements

We use off-balance sheet arrangements from time to time to facilitate financing of various projects. Off-balance sheet arrangements are often created for a single specified purpose, for example, to facilitate securitization, leasing, hedging, research and development, and reinsurance, or other transactions or arrangements. The following describes our major off-balance sheet arrangements excluding the investments we hold in various unconsolidated subsidiaries which are accounted for under the equity method (see Note 1(B) of the Notes to Financial Statements).

Guarantees We have entered into various contracts that are classified as guarantees under Interpretation 45. For further information, see Note 11(C)*(vii)* of the Notes to Financial Statements.

Retained Interest in Assets Transferred to an Unconsolidated Entity In February 2002, CG&E, PSI, and ULH&P replaced their existing agreement to sell certain of their accounts receivable and related collections. Cinergy Corp. formed Cinergy Receivables Company, LLC (Cinergy Receivables) to purchase, on a revolving basis, nearly all of the retail accounts receivable and related collections of our operating companies. Cinergy Corp. does not consolidate Cinergy Receivables since it meets the requirements to be accounted for as a qualifying special purpose entity. Our operating companies each retain an interest in the receivables transferred to Cinergy Receivables. The sales of receivables are accounted for under Statement of Financial Accounting Standards No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities* (Statement 140). For a more detailed discussion of our sales of accounts receivable, see Note 3(C) of the Notes to Financial Statements.

Derivative Instruments that are Classified as Equity In 2001, Cinergy Corp. issued approximately $316 million notional amounts of combined securities, a component of which was stock purchase contracts. These contracts obligate the holder to purchase common shares of Cinergy Corp. stock in February 2005. Since the stock purchase contracts are detachable and classified in equity the change in their fair value is not recorded in equity or earnings. For further information see Note 3(B) of the Notes to Financial Statements.

Variable Interest Entities (VIE) We hold interests in VIEs, consolidated and unconsolidated, as defined by Interpretation 46. For further information, see Note 1(Q)*(iv)* and Note 3(A) of the Notes to Financial Statements.

Securities Ratings

As of January 31, 2004, the major credit rating agencies rated our securities as follows:

	Fitch(1)	Moody's(2)	S&P(3)
Cinergy Corp.			
Corporate Credit	BBB+	Baa2	BBB+
Senior Unsecured Debt	BBB+	Baa2	BBB
Commercial Paper	F-2	P-2	A-2
Preferred Trust Securities	BBB+	Baa2	BBB
CG&E			
Senior Secured Debt	A-	A3	A-
Senior Unsecured Debt	BBB+	Baa1	BBB
Junior Unsecured Debt	BBB	Baa2	BBB-
Preferred Stock	BBB	Baa3	BBB-
Commercial Paper	F-2	P-2	Not Rated
PSI			
Senior Secured Debt	A-	A3	A-
Senior Unsecured Debt	BBB+	Baa1	BBB
Junior Unsecured Debt	BBB	Baa2	BBB-
Preferred Stock	BBB	Baa3	BBB-
Commercial Paper	F-2	P-2	Not Rated
ULH&P			
Senior Unsecured Debt	Not Rated	Baa1	BBB

(1) Fitch Ratings (Fitch)
(2) Moody's Investors Service (Moody's)
(3) Standard & Poor's Ratings Services (S&P)

The highest investment grade credit rating for Fitch is AAA, Moody's is Aaa1, and S&P is AAA.

The lowest investment grade credit rating for Fitch is BBB-, Moody's is Baa3, and S&P is BBB-.

A security rating is not a recommendation to buy, sell, or hold securities. These securities ratings may be revised or withdrawn at any time, and each rating should be evaluated independently of any other rating.

Equity

Under the SEC's June 2000 Order, Cinergy Corp. is permitted to increase its total capitalization by $5 billion (as previously discussed). The proceeds from any new issuances will be used for general corporate purposes.

Cinergy Corp. issued approximately 4.6 million shares in 2003, and approximately 3.2 million shares in 2002 to satisfy its obligations under its various employee stock plans and the Cinergy Corp. Direct Stock Purchase and Dividend Reinvestment Plan.

In February 2002, Cinergy Corp. issued 6.5 million shares of common stock with net proceeds of approximately $200 million.

In January 2003, Cinergy Corp. filed a registration statement with the SEC with respect to the issuance of common stock, preferred stock, and other securities in an aggregate offering amount of $750 million. In February 2003, we sold 5.7 million shares of common stock of Cinergy Corp. with net proceeds of approximately $175 million under this registration statement.

Cinergy Corp. contributed $200 million in capital to PSI in two separate $100 million capital contributions in the second and third quarters of 2003, respectively. These capital contributions were made to support PSI's current credit ratings.

Dividend Restrictions

Cinergy Corp.'s ability to pay dividends to holders of its common stock is principally dependent on the ability of CG&E and PSI to pay Cinergy Corp. common stock dividends. Cinergy Corp., CG&E, and PSI cannot pay dividends on their common stock if their respective preferred stock dividends or preferred trust dividends are in arrears. The amount of common stock dividends that each company can pay is also limited by certain capitalization and earnings requirements under CG&E's and PSI's credit instruments. Currently, these requirements do not impact the ability of either company to pay dividends on its common stock.

Other

Where subject to rate regulations, our operating companies have the ability to timely recover certain cash outlays through regulatory mechanisms such as fuel adjustment clause, purchased power tracker (Tracker), gas cost recovery, and construction work in progress (CWIP) ratemaking. For further discussion see Electric Industry and Gas Industry.

As opportunities arise, we will continue to monetize certain non-core investments, which would include our international assets and other technology investments.

Results of Operations

Summary of Results

Electric and gas gross margins and net income for the years ended December 31, 2003, 2002, and 2001 were as follows:

(in thousands)	2003	2002	2001
Electric gross margin	$2,224,936	$2,348,369	$2,201,081
Gas gross margin	331,673	280,488	258,368
Net income	469,772	360,576	442,279

Electric gross margins decreased for the year ended December 31, 2003 as compared to the same period last year. Milder weather in 2003 compared to 2002 contributed the most to decreased retail electric margins. In addition, electric gross margins associated with our natural gas peaking assets decreased in 2003 as compared to 2002. Partially offsetting these decreases were higher margins from physical and financial trading and an increase in rate tariff adjustments associated with certain construction programs.

Gas gross margins increased for the year ended December 31, 2003 as compared to the same period last year, primarily from an increase in base rates, as approved by the PUCO in May 2002, and tariff adjustments associated with the gas main replacement program and Ohio excise taxes. The colder weather in the first quarter of 2003 compared to 2002 also contributed to increased gas margins. In addition, in the second quarter of 2002 Cinergy Marketing & Trading, LP (Marketing & Trading) began engaging in storage and transportation activities. Higher gas trading margins as discussed later in Gas Operating Revenues also contributed to the increase.

Our net income increased for the year ended December 31, 2003, as compared to 2002, as a result of increases in gas gross margins as discussed above and lower *Operation and Maintenance* expense primarily a result of the recognition of higher costs in 2002 associated with employee severance programs. In addition, lower property taxes, primarily resulting from the change in property value assessment in the state of Indiana in 2003, contributed to our increase. Also contributing to our increase was the 2002 write-off of certain investments. Our increased net income reflects a net gain resulting from the implementation of certain accounting changes which have been reflected as a cumulative effect of changes in accounting principles. Our increased net income also reflects gains realized in 2003 and losses incurred in 2002 from the disposal of discontinued operations and lower income taxes resulting primarily from tax credits associated with the production of synthetic fuel, which began in July 2002. Offsetting these increases were decreases in electric gross margins.

Electric and gas gross margins increased and net income decreased for the year ended December 31, 2002 as compared to 2001. Gross margins were offset by the recognition of costs associated with employee severance programs, charges related to the write-off of certain investments, and higher operating costs. Gross margins were also offset by a cumulative effect of a change in accounting principle related to the implementation of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (Statement 142).

The explanations below follow the line items on the Consolidated Statements of Income. However, only the line items that varied significantly from prior periods are discussed.

Electric Operating Revenues

(in millions)	2003	2002	2001
Retail	$2,702	$2,785	$2,694
Wholesale	560	395	442
Other	121	158	80
Total	$3,383	$3,338	$3,216

Retail electric operating revenues decreased for the year ended December 31, 2003 as compared to 2002, mainly due to milder weather during the summer of 2003. Cooling degree days were down approximately 40 percent compared to last year. In addition, retail revenues decreased due to migration of customers to a transportation-only tariff, in connection with the Ohio electric customer choice program.

Electric wholesale revenues increased for the year ended December 31, 2003, as compared to 2002, primarily due to more generation capacity that was available for wholesale transactions and lower retail demand. In addition, our increase reflects higher margins on physical and financial trading primarily in and around the Midwest.

Other electric operating revenues decreased for the year ended December 31, 2003, as compared to 2002, primarily due to a reduction in third party coal sales. Our decrease also reflects lower transmission revenues primarily as a result of changes in the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) operations.

Retail electric operating revenues increased for the year ended December 31, 2002 as compared to 2001, reflecting an increased price received per megawatt hour (MWh) sales due to the changes in rate tariff adjustments associated with demand-side management, purchased power, CWIP, and fuel cost recovery programs. The cost of fuel for PSI's retail customers is passed on dollar-for-dollar under the state of Indiana mandated fuel cost recovery mechanism.

Wholesale electric operating revenues decreased for the year ended December 31, 2002 as compared to 2001, primarily due to a reduction in the average price per MWh realized on wholesale transactions related to energy marketing and trading activities.

Other electric operating revenues increased for the year ended December 31, 2002, as compared to 2001. The increase is due primarily to increases in third party coal sales and transmission revenues associated with the Midwest ISO which began operations in early 2002.

Gas Operating Revenues

(in millions)	2003	2002	2001
Retail	$623	$433	$587
Wholesale	71	68	61
Storage and Transportation	140	86	-
Other	2	3	8
Total	*$836*	*$590*	*$656*

Retail gas operating revenues increased for the year ended December 31, 2003 as compared to 2002, primarily due to a higher price received per thousand cubic feet (mcf) delivered. The increase in price was primarily the result of the colder weather in the first quarter of 2003, as compared to the same period in 2002, which drove up the demand and the price of natural gas. Wholesale gas commodity cost is passed directly to the retail customer dollar-for-dollar under the gas cost recovery mechanism mandated by state law. Additionally, the higher price per mcf reflects an increase in base rates, as approved by the

PUCO in May 2002, and tariff adjustments associated with the gas main replacement program, gas cost recovery mechanism, and Ohio excise taxes. Additionally, the amount of mcf delivered to customers increased as a result of colder weather in the first quarter of 2003, as compared to 2002.

Wholesale gas operating revenues (which represent net gains and losses on energy trading derivatives) increased for the year ended December 31, 2003, as compared to 2002, primarily due to an increase in the volatility of natural gas prices in the first quarter of 2003, as compared to the same period in 2002.

Gas storage and transportation operating revenues increased for the year ended December 31, 2003, as compared to 2002, primarily due to an increase in natural gas sold out of storage in 2003. Marketing & Trading began engaging in significant storage activities in the second quarter of 2002.

Retail gas operating revenues decreased for the year ended December 31, 2002, as compared to 2001, primarily due to a lower price received per mcf delivered. The lower price reflects a substantial decrease in the wholesale gas commodity cost, which is passed directly to the retail customer dollar-for-dollar under the gas cost recovery mechanism that is mandated by state law. Partially offsetting this decrease in retail gas revenues was an increase in base rates approved by the PUCO in May 2002 (See CG&E Gas Rate Case in Future Expectations/Trends — Gas Industry).

Wholesale gas operating revenues (which represent net gains and losses on energy trading derivatives) increased for the year ended December 31, 2002 as compared to 2001, primarily due to an increase in basis trading and the volatility of natural gas prices.

Gas storage and transportation operating revenues increased for the year ended December 31, 2002, as compared to 2001. Marketing & Trading began engaging in significant storage activities in the second quarter of 2002, resulting in increased revenues, which must be presented on a gross revenue basis.

Other Revenues

Other revenues increased for the year ended December 31, 2003, as compared to 2002 and 2001. This increase is primarily due to the sale of synthetic fuel, which began in July 2002.

Operating Expenses

(in millions)	2003	2002	2001
Fuel	$1,005	$ 886	$ 813
Purchased and exchanged power	153	104	201
Gas purchased	383	233	397
Gas storage and transportation	121	77	–
Operation and maintenance	1,276	1,292	1,008
Depreciation	419	405	367
Taxes other than income taxes	250	263	228
Total	$3,607	$3,260	$3,014

Fuel

Fuel primarily represents the cost of coal, natural gas, and oil that is used to generate electricity. The following table details the changes to fuel expense for the years ended December 31, 2003 and 2002:

(in millions)	2003	2002
Prior year's fuel expense	$ 886	$813
Increase (Decrease) due to change in:		
Price of fuel	23	(8)
Deferred fuel cost	70	(23)
Fuel consumption	18	23
Other(1)	8	81
Current year's fuel expense	$1,005	$886

(1) Includes costs of third party coal sales.

Deferred fuel cost represents changes in fuel expense associated with PSI's fuel adjustment charge, which recovers retail fuel costs from customers on a dollar-for-dollar basis. The fuel adjustment charge is calculated based on the estimated cost of fuel in the next three-month period. PSI records any under-recovery or over-recovery resulting from these differences as a deferred asset or liability until it is billed or refunded to its customers, at which point it is adjusted through fuel expense.

Purchased and Exchanged Power

Purchased and exchanged power expense increased for the year ended December 31, 2003, as compared to 2002. The increase was primarily the result of increases in price paid per MWh and a lower amount of deferred purchased power cost.

The decrease for the year ended December 31, 2002, as compared to 2001, primarily reflects a reduction in the average price paid per MWh. Wholesale electric on-peak commodity prices were approximately 23 percent lower, on average, as compared to 2001.

Gas Purchased

Gas purchased expense increased for the year ended December 31, 2003, as compared to 2002, primarily due to an increased average cost per mcf of gas purchased. In addition, gas customer usage increased approximately ten percent due to colder weather for the year ended December 31, 2003, as compared to the same period last year. Wholesale commodity cost is passed directly to the retail customer dollar-for-dollar under the gas cost recovery mechanism mandated by state law.

The decrease for the year ended December 31, 2002, as compared to 2001, is primarily due to a decrease in the average cost purchased per mcf for retail customer usage. Wholesale natural gas commodity spot prices were 16 percent lower on average for the year ended December 31, 2002, as compared to 2001.

Gas Storage and Transportation

Gas storage and transportation expense increased for the year ended December 31, 2003, as compared to 2002 and 2001, primarily due to an increase in natural gas sold out of storage in 2003. Marketing & Trading began engaging in significant storage activities in the second quarter of 2002. Gas storage expense is recognized on our Statements of Income as natural gas is sold from inventory.

Operation and Maintenance

Operation and maintenance expense decreased for the year ended December 31, 2003, as compared to 2002, primarily as a result of decreased transmission costs largely the result of changes in the Midwest ISO operations, the recognition of higher costs associated with employee severance programs in 2002, and a decrease in employee incentive costs. Our decrease was partially offset by costs associated with the production of synthetic fuel, which began in July 2002, the charges associated with our resolution of claims with respect to the bankruptcy of Enron Corp., and the increase in maintenance expense for our generating units and overhead lines.

The increase for the year ended December 31, 2002, as compared to 2001, reflects the recognition of costs associated with employee severance programs, which began in the second quarter of 2002. Also contributing to this increase were higher transmission costs, increased costs of employee compensation and benefit programs, and expenditures related to process improvement and performance measurement initiatives. Our increase also reflects increased amortization of demand-side management expenditures, costs associated with the production of synthetic fuel and increased operating costs for certain of our non-regulated investments.

Depreciation

Depreciation expense increased for the year ended December 31, 2003, as compared to 2002, primarily due to the addition of depreciable plant, including the addition of the depreciable equipment associated with the production of synthetic fuel. Partially offsetting the increase was a decrease attributable to an increase in the estimated useful lives of certain CG&E assets resulting from a new depreciation study completed during the third quarter of 2003. Also offsetting this increase was the discontinuance of accruing costs of removal for CG&E's generating assets (which was previously included as part of *Depreciation* expense) as a result of the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (Statement 143). See Note 1(Q)*(iii)* of the Notes to Financial Statements for further details. Prior periods were not restated for the adoption of Statement 143.

The increase for the year ended December 31, 2002, as compared to 2001, was primarily attributable to the addition of depreciable plant, including the acquisitions of non-regulated peaking generation in 2001 and the previously mentioned synthetic fuel equipment in 2002.

Taxes Other Than Income Taxes

Taxes other than income taxes expense decreased for the year ended December 31, 2003, as compared to 2002, primarily resulting from lower property taxes partially offset by increased excise taxes. This decrease in property taxes is primarily a result of a change in property value assessments in the state of Indiana in 2003.

The increase for the year ended December 31, 2002, as compared to 2001, is primarily attributable to increased property taxes. The increase also reflects other tax changes associated with deregulation in Ohio.

Equity in Earnings (Losses) of Unconsolidated Subsidiaries

Equity in earnings (losses) of unconsolidated subsidiaries increased for the year ended December 31, 2002, as compared to 2001, primarily due to changes in the market valuation of certain investments and the dissolution and write-off of subsidiaries in 2001.

Miscellaneous Income — Net

Miscellaneous Income — Net increased for the year ended December 31, 2003, as compared to 2002. The increase primarily reflects the 2002 write-offs of certain equipment and technology investments and costs accrued related to the termination of a contract for the construction of combustion turbines. Also contributing to the increase was the interest income on the notes receivable of two newly consolidated subsidiaries in 2003. See Note 1(Q)*(iv)* of the Notes to Financial Statements for further details. Partially offsetting these increases were net gains realized in 2002 from the sale of equity investments in certain renewable energy projects. Our increase also reflects a gain on the sale of non-utility property.

The decrease for the year ended December 31, 2002, as compared to 2001, primarily reflects the write-off of technology investments and costs accrued related to the termination of a contract for the construction of combustion turbines. Partially offsetting this decrease were net gains realized from the sale of equity investments in certain renewable energy projects.

Interest Expense

Interest Expense increased for the year ended December 31, 2003, as compared to 2002, primarily as a result of an increase in average long-term debt outstanding during the year ended December 31, 2003. The increase also reflects charges during 2003 associated with the re-financing of certain debt and the additional debt recorded with the consolidation of two new entities and the recognition of a note payable to a trust in accordance with the adoption of Interpretation 46. See Note 1(Q)*(iv)* of the Notes to Financial Statements for further details. The increase was partially offset by a decrease in short-term interest rates.

The decrease for the year ended December 31, 2002, as compared to 2001, was primarily a result of lower interest rates.

Preferred Dividend Requirement of Subsidiary Trust

Preferred Dividend Requirement of Subsidiary Trust relates to quarterly payments to be made to holders of our preferred trust securities, which were issued in December 2001.

Preferred Dividend Requirement of Subsidiary Trust decreased for the year ended December 31, 2003, as compared to 2002, as a result of the implementation of Interpretation 46. Effective July 1, 2003, the preferred trust securities and the related dividends are no longer reported in our financial statements. However, interest expense is still being incurred on a note payable to this trust. See Note 1(Q)*(iv)* of the Notes to Financial Statements for further details.

Income Taxes

The effective income tax rate decreased for the year ended December 31, 2003, as compared to 2002 and 2001. The decrease was primarily a result of the tax credits associated with the production and sale of synthetic fuel by a non-regulated subsidiary, which began in July 2002. Our effective tax rate for 2003 was approximately 25 percent.

Discontinued Operations

In 2002, we sold and/or classified as held for sale, several non-core investments, including renewable and international investments. During 2003, we completed the disposal of our gas distribution operation in South Africa, sold our remaining wind assets in the U.S., and substantially sold or liquidated the assets of our energy marketing business in the Czech Republic. Pursuant to Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment of Long-lived Assets* (Statement 144), these investments have been classified as discontinued operations in our financial statements. See Note 14 of the Notes to Financial Statements for additional information.

The increase in discontinued operations in 2003 as compared to 2002 is due to the recognition of losses on disposal of foreign investments in 2002 and the recognition of gains on disposal in 2003.

Cumulative Effect of Changes in Accounting Principles

In 2003, we recognized *Cumulative effect of changes in accounting principles, net of tax* gain of approximately $26 million. The cumulative effect of changes in accounting principles was a result of the adoption of Statement 143, and the rescission of Emerging Issues Task Force (EITF) Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 98-10).

In 2002, we recognized a *Cumulative effect of a change in accounting principle, net of tax* loss of approximately $11 million as a result of the implementation of Statement 142. See Note 1(Q)*(vi)* of the Notes to Financial Statements for further information.

FUTURE EXPECTATIONS/TRENDS

In the Future Expectations/Trends section, we discuss electric and gas industry developments, market risk sensitive instruments and positions, and accounting matters. Each of these discussions will address the current status and potential future impact on our results of operations and financial condition.

ELECTRIC INDUSTRY

Retail Market Developments

Currently, regulatory and legislative initiatives shaping the transition to a competitive retail market are the responsibilities of the individual states. Many states, including Ohio, have enacted electric utility deregulation legislation. In general, these initiatives have sought to separate the electric utility service into its basic components (generation, transmission, and distribution) and offer each component separately for sale. This separation is referred to as unbundling of the integrated services. Under the customer choice initiative in Ohio, we continue to transmit and distribute electricity; however, the customer can purchase electricity from any available supplier, and we are compensated through a transportation charge. The following sections further discuss the current status of federal and state energy policies and deregulation legislation in the states of Ohio, Indiana, and Kentucky, each of which includes a portion of our service territory.

Energy Bill The U.S. House of Representatives (House) passed the Energy Policy Act in April 2003. The legislation, as passed in the House, included the repeal of the PUHCA, as well as tax incentives for gas and electric distribution lines, and combined heat and power and renewable energy projects. The U.S. Senate (Senate) Energy and Natural Resources Committee passed its version of comprehensive energy legislation in April 2003. A conference agreement which merged both the House and Senate versions passed in the House in October 2003, but failed to pass in the Senate. The legislation can be considered during this session of Congress, however many disputed issues remain and it is unclear whether or not legislation will pass this year.

Clear Skies Legislation President Bush has proposed environmental legislation that would combine a series of Clean Air Act requirements, including the recently proposed regulations for mercury and particulate matter for coal-fired power plants with a legislative solution that includes trading and specific emissions reductions and timelines to meet those reductions.

The President's "Clear Skies Initiative" would seek an overall 70 percent reduction in emissions from power plants over a phased-in reduction schedule beginning in 2010 and continuing through 2018. The Senate Environment and Public Works Committee has held several hearings on the "Clear Skies Initiative" proposal. It is unclear whether or not this legislation will be considered in 2004.

Ohio CG&E is in a market development period, transitioning to deregulation of electric generation and a competitive retail electric service market in the state of Ohio. The transition period is governed by the Amended Substitute Senate Bill No. 3 (Electric Restructuring Bill) and a stipulated transition plan adopted and approved by the PUCO. The Electric Restructuring Bill provides for a market development period that began January 1, 2001, and ends no later than December 31, 2005.

The major features of CG&E's transition plan include:

- Residential customer rates are frozen through December 31, 2005;
- Residential customers received a five percent reduction in the generation portion of their electric rates, effective January 1, 2001;
- CG&E will provide $4 million from 2001 to 2005 in support of energy efficiency and weatherization services for low income customers;
- CG&E will provide shopping credits to switching customers;
- The creation of a Regulatory Transition Charge (RTC) designed to recover CG&E's regulatory assets and other transition costs over a ten-year period;
- Authority for CG&E to transfer its generation assets to one or more, non-regulated affiliates to provide flexibility to manage its generation asset portfolio in a manner that enhances opportunities in a competitive marketplace;
- Authority for CG&E to apply the proceeds of transition cost recovery to costs incurred during the transition period, including implementation costs and purchased power costs that may be incurred by CG&E to maintain an operating reserve margin sufficient to provide reliable service to its customers;
- Authority for CG&E to adjust the amortization of its regulatory assets and other transition costs to reflect the effects of any shopping incentives provided to customers; and
- CG&E will provide standard offer default supplier service (i.e., CG&E will be the supplier of last resort, so that no customer will be without an electric supplier).

Under CG&E's transition plan, retail customers continue to receive transmission and distribution services from CG&E, but may purchase electricity from another supplier. Retail customers that purchase electricity from another supplier receive shopping credits from CG&E. The shopping credits generally reflect the costs of electric generation included in CG&E's frozen rates. However, shopping credits for the first 20 percent of electricity usage in each customer class to switch suppliers are higher than shopping credits for subsequent switchers in order to stimulate the development of the competitive retail electric service market.

CG&E recovers its generation-related regulatory assets and certain other deferred transition costs through an RTC paid by all retail customers. As the RTC is collected from customers, CG&E amortizes the deferred balance of regulatory assets and other transition costs. A portion of the RTC collected from customers is recognized currently as a return on the deferred balance of regulatory assets and other transition costs and as reimbursement for the difference in the shopping credits provided to retail customers and the wholesale revenues from generation made available by switched customers. The ability of CG&E to recover its regulatory assets and other transition costs is dependent on several factors, including, but not limited to, the level of CG&E's electric sales, prices in the wholesale power markets, and the amount of customers switching to other electric suppliers.

In January 2003, CG&E filed an application with the PUCO for approval of a methodology to establish how market-based rates for non-residential customers will be determined when the market development period ends. In the filing, CG&E seeks to establish a market-based standard service offer rate for non-residential customers that do not switch suppliers and a process for establishing the competitively-bid generation service option required by the Electric Restructuring Bill. As of December 31, 2002, more than 20 percent of the load of CG&E's commercial and industrial customer classes had switched to other electric suppliers, and the other public authorities group was at 19.95 percent at December 31, 2003. Under its transition plan, CG&E may end the market development period for those classes of customers once 20 percent switching has been achieved; however, PUCO approval of the standard service offer rate and competitive bidding process is required before the market development period can be ended.

In December 2003, the PUCO issued an order that the CG&E application filed in January 2003 would proceed to a hearing and be consolidated with CG&E's application to defer certain administrative transmission charges and the application to defer costs of capital investments made to their transmission and distribution system during the market development period. As part of this order, the PUCO requested that CG&E file a rate stabilization plan to mitigate the effects of market based pricing on retail customers while the competitive retail electric market continues to mature. In response to this request, on January 26, 2004, CG&E filed an offer of settlement, including an electric reliability and rate stabilization plan. In this proposal, CG&E has also asked to end the market development period for all customers effective December 31, 2004.

The major features of CG&E's electric reliability and rate stabilization plan include:

- The market development period would end for all customers on December 31, 2004;
- CG&E would begin to collect a non-bypassable Provider of Last Resort (POLR) charge from all customers effective January 1, 2005. This charge could be increased by up to 10 percent of CG&E's generation charge each year from 2005 through 2008;
- CG&E would offer its current generation rates as its market based rates until December 31, 2008;
- CG&E would request a transmission and distribution rate increase effective January 1, 2005;
- CG&E would begin charging RTC as an explicit wires charge;
- PUCO approval of previously requested transmission and distribution deferrals and cost recovery riders (see CG&E Transmission and Distribution Rate Filings);
- The five percent generation rate reduction for residential customers would continue through 2008; and
- Extend recovery of residential RTC from 2008 through 2010.

The POLR charge would allow for recovery of increased costs of fuel and purchased power, transmission congestion, environmental compliance, homeland security, taxes and maintaining an adequate reserve margin.

An evidentiary hearing addressing the issues described above is scheduled for the second quarter of 2004. At the current time CG&E is unable to predict the outcome of this proceeding or the effects it could have on its results of operations or financial condition.

Indiana In 2002, Indiana lawmakers anticipated the creation of an Indiana Energy Policy Commission to assist in the creation of a comprehensive energy plan. However, no such commission was formed and, as a result, there are no current plans for electric deregulation in Indiana.

Kentucky Throughout 1999, a special Kentucky Electricity Restructuring Task Force (Task Force), convened by the Kentucky legislature, studied the issues of electric deregulation. In January 2000, the Task Force issued a final report to former Kentucky Governor Paul Patton recommending that lawmakers wait until the 2002 General Assembly before considering any deregulation that would open the state's electric industry to competition. The state legislature did not take any action in either 2002 or 2003 to move Kentucky towards electric deregulation.

Other States At the end of 2000, approximately one half of the states and the District of Columbia had adopted deregulation plans. However, recent events are significantly influencing political and legislative activity. At the end of 2001, eight of the states decided to delay or suspend their deregulation activities. No additional states adopted deregulation plans during 2002 or 2003, and two states repealed their deregulation statutes during 2003.

Retail Supply-Side Actions In December 2002, the IURC approved a settlement agreement among PSI, the Indiana Office of the Utility Consumer Counselor, and the IURC Testimonial Staff authorizing PSI's purchases of the Henry County, Indiana and Butler County, Ohio, gas-fired peaking plants from two non-regulated affiliates. In February 2003, the FERC issued an order under Section 203 of the Federal Power Act authorizing PSI's acquisitions of the plants, which occurred on February 5, 2003. Subsequently, in April 2003, the FERC issued a tolling order allowing additional time to consider a request for rehearing filed in response to the February 2003 FERC order. At this time, the rehearing request is still pending before the FERC, and PSI cannot predict the outcome of this matter.

In July 2003, ULH&P filed an application with the KPSC requesting a certificate of public convenience and necessity to acquire CG&E's 68.9 percent ownership interest in the East Bend Generating Station, located in Boone County, Kentucky, the Woodsdale Generating Station, located in Butler County, Ohio, and one generating unit at the four-unit Miami Fort Station located in Hamilton County, Ohio. In December 2003, the KPSC conditionally approved this application. The transfer, which will be made at net book value, will not affect current electric rates for ULH&P's customers, as power will be provided under the same terms as under the current wholesale power contract with CG&E through at least December 31, 2006. ULH&P will also seek regulatory approval for aspects of this transaction from the FERC and SEC. At this time, ULH&P is unable to predict the outcome of this matter.

Other Under generally accepted accounting principles (GAAP), CG&E, PSI, and ULH&P apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (Statement 71) to the applicable rate-regulated portions of their businesses. The provisions of Statement 71 allow CG&E, PSI, and ULH&P to capitalize (record as a deferred asset) costs that would normally be charged to expense. These costs are classified as regulatory assets in the accompanying financial statements, and the majority have been approved by regulators for future recovery from customers through our rates. As of December 31, 2003, our operating companies have approximately $1 billion of net regulatory assets, of which approximately 90 percent has been approved for recovery.

Except with respect to the generation assets of CG&E, as of December 31, 2003, our operating companies continue to meet each of the criteria required for the application of Statement 71. However, to the extent other states implement deregulation legislation, the application of Statement 71 will need to be reviewed. Based on our operating companies' current regulatory orders and the regulatory environment in which they currently operate, management believes the future recovery of regulatory assets recognized in the accompanying Balance Sheets as of December 31, 2003, is probable. See Note 1(C) of the Notes to Financial Statements for a further discussion of our regulatory assets.

FERC and Midwest ISO

Historical As part of the effort to create a competitive wholesale power marketplace, the FERC approved the formation of the Midwest ISO during 1998. In that same year, Cinergy agreed to join the Midwest ISO in preparation for meeting anticipated changes in the FERC regulations and future deregulation requirements. The Midwest ISO was established as a non-profit organization to maintain functional control over the combined transmission systems of its members.

The FERC has also approved the formation of the PJM Interconnection, LLC (PJM) and has ordered the Midwest ISO, PJM, and various other parties to establish certain protocols in an attempt to create a structured, connected market among all utility companies.

Unbundled Adder Service Fees The FERC issued an order in December 2001, in response to protests of the Midwest ISO's proposed methodology related to the calculation of its administrative adder fees for the services it provides. Cinergy and a number of other parties filed protests to the proposed methodology, suggesting, among other things, that the methodology was inconsistent with the transmission owners' prior agreement with the Midwest ISO and selectively allowed only independent transmission companies to choose which unbundled administrative adder services they wished to purchase from the Midwest ISO. A partial settlement was reached in the FERC proceeding, resolving the issues addressed by Cinergy's protest in a manner satisfactory to Cinergy. The settlement agreement was approved by the FERC in a February 2003 order with implementation initiated on March 1, 2003. The settlement resulted in approximately $25 million of administrative adder credits to be shared among the Midwest ISO transmission owners and customers responsible for administrative charges. Cinergy's share was approximately $3 million.

Standard Electricity Market Design (SMD) The FERC issued a Notice of Proposed Rulemaking (NOPR) in 2002 on "Remedying Undue Discrimination through Open Access Transmission Service and SMD". This NOPR would have required all public utilities with open access transmission tariffs to file modifications to their tariffs to implement FERC's proposed standardized transmission services and standardized wholesale electric market design. The FERC has not taken action on this NOPR. In addition, because we are a member of the Midwest ISO and the Midwest ISO is actively moving forward in an attempt to create a structured market, it is unlikely that the FERC's SMD NOPR will have a material, if any, effect on our financial position or results of operations.

Day-Ahead and Real-Time Energy Markets In response to prior FERC orders, in July 2003, the Midwest ISO filed with the FERC proposed changes to its existing transmission tariff to add terms and conditions to implement Day-Ahead and Real-Time Energy Markets and Financial Transmission Rights (Energy Markets Tariff). In October 2003, the FERC approved a Midwest ISO filing to withdraw this Energy Markets Tariff. Cinergy anticipates that the Midwest ISO will file a new Energy Markets Tariff at sometime in the future; however, at this time, Cinergy cannot predict the effect any such filing will have on its results of operations.

Significant Rate Developments

PSI Retail Electric Rate Case In December 2002, PSI filed a petition with the IURC seeking approval of a base retail electric rate increase. PSI has filed initial and rebuttal testimony in this case and the final set of hearings took place in November 2003. PSI filed its proposed order in December 2003. Based on updated testimony filed in October 2003 and the proposed order, PSI proposes an increase in annual revenues of approximately $180 million, or an average increase of approximately 14 percent over PSI's retail electric rates in effect at the end of 2002. An IURC decision is anticipated by the end of the first quarter of 2004.

PSI Fuel Adjustment Charge In June 2001, PSI filed a petition with the IURC requesting authority to recover $16 million in under billed deferred fuel costs incurred from March 2001 through May 2001. The IURC approved recovery of these costs subject to refund pending the findings of an investigative sub-docket. The sub-docket was opened to investigate the reasonableness of, and underlying reasons for, the under billed deferred fuel costs. A hearing was held in July 2002, and in March 2003 the IURC issued an order giving final approval to PSI's recovery of the $16 million.

PSI CWIP Ratemaking Treatment for NO_X Equipment In April 2003, PSI filed an application with the IURC requesting that its CWIP rate adjustment mechanism be updated for expenditures through December 2002 related to NO_X equipment currently being installed at certain PSI generation facilities. CWIP ratemaking treatment allows for the recovery of carrying costs on certain pollution control equipment while and after the equipment is under construction. A final order was issued in September 2003. The order granted substantially all of PSI's requested relief, leaving only the issue of whether certain specific equipment qualified for CWIP ratemaking treatment to be decided in the first half of 2004. This CWIP rate mechanism adjustment resulted in less than a one percent increase in customer rates.

In October 2003, PSI filed an application with the IURC requesting that its CWIP rate adjustment mechanism be updated for additional expenditures through September 30, 2003, related to NO_X equipment currently being installed at certain PSI generation facilities. If the application is approved, it will result in the recovery of an additional $7 million. An order on this third CWIP update case is expected in the first half of 2004.

PSI's initial CWIP rate mechanism adjustment (authorized in July 2002) resulted in an approximately one percent increase in customer rates. Under the IURC's CWIP rules, PSI may update its CWIP tracker at six-month intervals. The first such update to PSI's CWIP rate mechanism occurred in the first quarter of 2003. The IURC's July 2002 order also authorized PSI to defer, for subsequent recovery, post-in-service depreciation and to continue the accrual for allowance for funds used during construction (AFUDC). Pursuant to Statement of Financial Accounting Standards No. 92, *Regulated Enterprises-Accounting for Phase-in Plans*, the equity component of AFUDC will not be deferred for financial reporting after the related assets are placed in service.

PSI Environmental Compliance Cost Recovery In 2002, the Indiana General Assembly passed legislation that, among other things, encourages the deployment of advanced technologies that reduce regulated air emissions, while allowing the continued use of high sulfur Midwest coal in existing electric generating plants. The legislation authorizes the IURC to provide financial incentives to utilities that deploy such advanced technologies. PSI sought IURC approval, under this new law, of a cost tracking mechanism for PSI's NO_X equipment-related depreciation and operation and maintenance costs, authority to use accelerated (18-year) depreciation for its NO_X compliance equipment, and approval of a NO_X emission allowance purchase and sales tracker. In October 2003, PSI reached a settlement with the other parties to this case that provides for the relief described above for most of PSI's environmental compliance equipment. In December 2003, the IURC approved the settlement agreement. Previously, the majority of these costs (the post-in-service depreciation costs) were being deferred pursuant to the July 2002 CWIP order described above, and as a result, the settlement agreement did not have a material impact on PSI's results of operations or financial condition.

PSI Purchased Power Tracker The Tracker was designed to provide for the recovery of costs related to certain specified purchases of power necessary to meet native load customers' summer peak demand requirements to the extent such costs are not recovered through the existing fuel adjustment clause.

PSI is authorized to seek recovery of 90 percent of its purchased power expenses through the Tracker (net of the displaced energy portion recovered through the fuel recovery process and net of the mitigation credit portion), with the remaining 10 percent deferred for subsequent recovery in PSI's general retail electric rate case. In March 2002, PSI filed a petition with the IURC seeking approval to extend the Tracker process beyond the summer of 2002. A hearing was held in January 2003, and in June 2003 the IURC approved the extension for up to an additional two years with the ultimate determination concerning PSI's continued use of the Tracker process to be made in PSI's pending retail electric rate case.

In June 2002, PSI also filed a petition with the IURC seeking approval of the recovery through the Tracker of its actual summer 2002 purchased power costs. In May 2003, the IURC approved PSI's recovery of $18 million related to its summer 2002 purchased power costs, and also authorized $2 million of deferred costs sought for recovery in PSI's general retail electric rate case.

CG&E Transmission and Distribution Rate Filings

In October 2003, CG&E filed an application with the PUCO seeking deferral of approximately $173 million, of which approximately $42 million has been incurred as of December 31, 2003, in depreciation, property taxes and carrying costs related to net additions to transmission and distribution utility plant in service from January 2001 through December 2005. Rates are frozen in Ohio under the state's electric restructuring law from 2001 through the end of the market development period. CG&E has not deferred any of these costs as of December 31, 2003.

CG&E is proposing a mechanism to recover costs related to net additions to transmission and distribution utility plant in service after the end of the market development period. The mechanism would work in a similar manner to the monthly customer charge the PUCO approved for CG&E's accelerated natural gas main replacement program, discussed below in CG&E Gas Rate Case, which is adjusted annually based on expenditures in the previous year.

In the alternative electric reliability and rate stabilization proposal that CG&E filed in January 2004 with the PUCO, which is described in more detail in the Ohio section, CG&E made an alternative proposal to seek deferrals of transmission and distribution utility plant in service from January 2003 through December 2004, for the PUCO to declare an end to the market development period effective December 31, 2004, and for CG&E to file a transmission and distribution base rate case in 2004 to be effective January 1, 2005. The alternative proposal also includes tracking mechanisms as described in the preceding paragraph, which would recover ongoing transmission and distribution costs.

GAS INDUSTRY

Significant Rate Developments

CG&E Gas Rate Case In the third quarter of 2001, CG&E filed a retail gas rate case with the PUCO seeking to increase base rates for natural gas distribution service and requesting recovery through a tracking mechanism of the costs of an accelerated gas main replacement program with an estimated capital cost of $716 million over 10 years. An order was issued in May 2002, in which the PUCO authorized a base rate increase of approximately $15 million, or 3.3 percent overall, effective May 30, 2002. In addition, the PUCO authorized CG&E to implement the tracking mechanism to recover the costs of the accelerated gas main replacement program, subject to certain rate caps that increase in amount annually through May 2007, through the effective date of new rates in CG&E's next retail gas rate case. In April 2003, CG&E received approval to increase its rates under the tracking mechanism by $6.5 million. This increase was effective in May 2003. CG&E filed another application in January 2004 to increase its rates by approximately $7 million under the tracking mechanism. CG&E expects that the PUCO will rule on this application in the second quarter of 2004.

ULH&P Gas Rate Case In the second quarter of 2001, ULH&P filed a retail gas rate case with the KPSC seeking to increase base rates for natural gas distribution services and requesting recovery through a tracking mechanism of the costs of an accelerated gas main replacement program with an estimated capital cost of $112 million over 10 years. Through December 31, 2003, ULH&P has recovered approximately $1.4 million under this tracking mechanism. The Kentucky Attorney General has appealed to the Franklin Circuit Court the KPSC's approval of the tracking mechanism and the KPSC's orders approving the new tracking mechanism rates. At the present time, ULH&P cannot predict the timing or outcome of this litigation.

Gas Distribution Plant In June 2003, the PUCO approved an amended settlement agreement between CG&E and the PUCO Staff in a gas distribution safety case arising out of a gas leak at a service head-adapter (SHA) style riser on CG&E's distribution system. The amended settlement agreement required CG&E to expend a minimum of $700,000 to replace SHA risers by December 31, 2003, and to file a comprehensive plan addressing all SHA risers on its distribution system. Cinergy has an estimated 190,000 SHA risers on its distribution system, of which 155,000 are in CG&E's service area and 31,000 are in ULH&P's service area. Further investigation as to whether any additional SHA risers will need maintenance or replacement is ongoing. If CG&E and ULH&P determine that replacement of all SHA risers is appropriate, we currently estimate that the replacement cost could be up to approximately $70 million. CG&E and ULH&P would pursue recovery of this cost through rates. At this time, Cinergy, CG&E, and ULH&P cannot predict the outcome of this matter.

Gas Prices

Natural gas prices escalated dramatically during the fourth quarter of 2002 and peaked midway through the first quarter of 2003. These higher natural gas prices moderated throughout the spring and summer of 2003 but for 2004 are expected to remain higher than previous years. Price movement will be driven by the effects of weather conditions, availability of supply, and changes in demand and storage inventories. Currently, neither CG&E nor ULH&P profit from changes in the cost of natural gas since natural gas purchase costs are passed directly to the customer dollar-for-dollar under the gas cost recovery mechanism that is mandated under state law. These higher natural gas prices could lead to decreases in the purchase price obtained on receivables sold to Cinergy Receivables due to an increased concern regarding realization of those receivables, however we believe the overall impact will be immaterial.

In July 2003, CG&E filed an application with the PUCO for approval to begin adjusting its gas cost adjustment rates on a monthly basis commencing in September 2003. In August 2003, the PUCO approved the change from quarterly to monthly. In September 2003, ULH&P filed a similar application with the KPSC for monthly gas cost adjustment rates. The KPSC approved this change and ULH&P began billing on a monthly basis in December 2003.

In May 2003, ULH&P filed an application with the KPSC requesting approval of a gas procurement-hedging program designed to mitigate the effects of gas price volatility on customers. In June 2003, the KPSC approved the hedging program through March 31, 2005. The program will allow the pre-arranging of between 20-75 percent of winter heating season base load gas requirements and up to 50 percent of summer season base load gas requirements. CG&E similarly hedges its gas procurement costs, however CG&E's gas procurement-hedging program has not been pre-approved by the PUCO but rather it is subject to PUCO review as part of the normal gas cost recovery process.

CG&E and ULH&P use primarily fixed price forward contracts and contracts with a ceiling and floor on the price. These contracts employ the normal purchases and sales scope exception, and do not involve hedges under Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (Statement 133).

MARKET RISK SENSITIVE INSTRUMENTS AND POSITIONS

Energy Commodities Sensitivity

The transactions associated with Commercial Business Units' (Commercial) (formerly named the Energy Merchant Business Unit) energy marketing and trading activities give rise to various risks, including price risk. Price risk represents the potential risk of loss from adverse changes in market price of electricity or other energy commodities. As Commercial continues to develop its energy marketing and trading business (and due to its substantial investment in generation assets), its exposure to movements in the price of electricity and other energy commodities may become greater. As a result, we may be subject to increased future earnings volatility.

Commercial's energy marketing and trading activities principally consist of Marketing & Trading's natural gas marketing and trading operations, Cinergy Global Trading

Limited's (Global Trading) European natural gas and power trading operations, and CG&E's and PSI's power marketing and trading operations. Our domestic operations market and trade over-the-counter (an informal market where the buying/selling of commodities occurs) contracts for the purchase and sale of electricity (primarily in the Midwest region of the U.S.), natural gas, and other energy-related products. In addition, our domestic operations also market and trade natural gas and other energy-related products on the New York Mercantile Exchange. Global Trading's operations trade over-the-counter contracts for the purchase and sale of natural gas and electricity (both primarily in the United Kingdom). Global Trading also trades natural gas on the International Petroleum Exchange.

Many of the contracts in both the accrual and trading portfolios commit us to purchase or sell electricity, natural gas, and other energy-related products at fixed prices in the future. The majority of the contracts in the natural gas and other energy-related product portfolios are financially settled contracts (i.e., there is no physical delivery related with these items). In addition, Commercial also markets and trades over-the-counter option contracts. The use of these types of commodity instruments is designed to allow Commercial to:

- manage and economically hedge contractual commitments;
- reduce exposure relative to the volatility of cash market prices;
- take advantage of selected arbitrage opportunities; and
- originate customized transactions with municipalities and end-use customers.

Commercial structures and modifies its net position to capture the following:

- expected changes in future demand;
- seasonal market pricing characteristics;
- overall market sentiment; and
- price relationships between different time periods and trading regions.

At times, a net open position is created or is allowed to continue when Commercial believes future changes in prices and market conditions may possibly result in profitable positions. Position imbalances can also occur due to the basic lack of liquidity in the wholesale power market. The existence of net open positions can potentially result in an adverse impact on our financial condition or results of operations. This potential adverse impact could be realized if the market price of electric power does not react in the manner or direction expected. Cinergy's Risk Management Control Policy contains limits associated with the overall size of net open positions for each trading operation and for Cinergy in total.

Value at Risk (VaR) Commercial measures the market risk inherent in the trading portfolio employing VaR analysis and other methodologies, which utilize forward price curves in electric power and natural gas markets to quantify estimates of the magnitude and probability of future value changes related to open contract positions. VaR is a statistical measure used to quantify the potential change in fair value of the trading portfolio over a particular period of time, with a specified likelihood of occurrence, due to market movement. Commercial, through some of our non-regulated subsidiaries, markets physical natural gas and electricity and trades derivative commodity instruments which are usually settled in cash including: forwards, futures, swaps, and options. Any transaction, whether settled physically or financially, that is accounted for at fair value is included in the VaR calculation.

Our VaR is reported based on a 95 percent confidence interval, utilizing a one-day holding period. This means that on a given day (one-day holding period) there is a 95 percent chance (confidence level) that our trading portfolio will not change more than the stated amount. Our VaR model uses the variance-covariance statistical modeling technique and historical volatilities and correlations over the past 21-trading day period. The average VaR was calculated using an average of trading days over the entire year and the high and low VaR were based on an entire year of trading day calculations. The market prices used to calculate VaR are obtained from exchanges and over-the-counter markets when available, established pricing models and other factors including market volatility, the time value of money, and location differentials. The VaR for Cinergy's trading portfolio is presented in the table below:

VaR Associated with Energy Trading Contracts

	2003		2002	
(dollars in millions)	Trading VaR	Percentage of Operating Income	Trading VaR	Percentage of Operating Income
95% confidence level, one-day holding period, one-tailed				
December 31	$0.6	0.1%	$1.6	0.2%
Average for the twelve months ended December 31	1.3	0.2	2.1	0.3
High for the twelve months ended December 31	3.8	0.7	3.7	0.5
Low for the twelve months ended December 31	0.4	0.1	0.5	0.1

Changes in Fair Value The changes in fair value of the energy risk management assets and liabilities for the years ended December 31, 2003 and 2002 are presented in the table below:

(in millions)	Changes in Fair Value 2003	2002
Fair value of contracts outstanding at the beginning of period	$ 75	$ 18
Inception value of new contracts when entered(1)	–	*6*
Changes in fair value attributable to changes in valuation techniques and assumptions(2)	1	14
Other changes in fair value(3)	127	89
Option premiums paid/(received)	(3)	20
Accounting Changes(4)		
Cumulative effect of changes in accounting principles	(20)	–
Consolidation of previously unconsolidated entities	7	–
Contract reclassification(5)	–	14
Contract acquisitions(6)	–	(16)
Contracts settled	(146)	(70)
Fair value of contracts outstanding at end of period	$ 41	$ 75

(1) Represents fair value, recognized in income, attributable to long-term, structured contracts, primarily in power, which is recorded on the date a deal is signed. These contracts are primarily with end-use customers or municipalities that seek to limit their risk to power price volatility. While caps and floors often exist in such contracts, the amount of power supplied can vary from hour to hour to mirror the customers' load volatility. See Note 1(Q)(i) of the Notes to Financial Statements for additional information regarding inception gains.

(2) Represents changes in fair value recognized in income, caused by changes in assumptions used in calculating fair value or changes in modeling techniques.

(3) Represents changes in fair value recognized in income, primarily attributable to fluctuations in price. This amount includes both realized and unrealized gains on energy trading contracts.

(4) See Note 1(Q)(iv) and Note 1(Q)(vi) of the Notes to Financial Statements for further information.

(5) Represents reclassifications of the settlement value of contracts that have been terminated as a result of counterparty non-performance to Non-Current Liabilities-Other. These contracts no longer have price risk and are therefore not considered energy trading contracts.

(6) Cinergy Capital & Trading, Inc. (Capital & Trading) acquired a portfolio of gas contracts and inventory in July 2002. This amount represents the fair value of net Energy risk management liabilities assumed.
There was no inception gain or loss recognized at the date of acquisition.

The following are the balances at December 31, 2003, and 2002 of our energy risk management assets and liabilities:

(in millions)	2003	2002
Energy risk management assets — current	$305	$464
Energy risk management assets — non-current	97	163
Energy risk management liabilities — current	(296)	(408)
Energy risk management liabilities — non-current	(65)	(144)
	$41	$75

The following table presents the expected maturity of the energy risk management assets and liabilities as of December 31, 2003:

(in millions)

	Fair Value of Contracts at December 31, 2003				
	Maturing				Total
Source of Fair Value(1)	2004	2005-2006	2007-2008	Thereafter	Fair Value
Prices actively quoted	$(2)	$18	$–	$ –	$16
Prices based on models and other valuation methods(2)	11	15	4	(5)	25
Total	$ 9	$33	$4	$(5)	$41

(1) While liquidity varies by trading regions, active quotes are generally available for two years for standard electricity transactions and three years for standard gas transactions. Non-standard transactions are classified based on the extent, if any, of modeling used in determining fair value. Long-term transactions can have portions in both categories depending on the tenor.

(2) A substantial portion of these amounts include option values.

Concentrations of Credit Risk Credit risk is the exposure to economic loss that would occur as a result of nonperformance by counterparties, pursuant to the terms of their contractual obligations. Specific components of credit risk include counterparty default risk, collateral risk, concentration risk, and settlement risk.

(i) Trade Receivables and Physical Power Portfolio Our concentration of credit risk with respect to trade accounts receivable from electric and gas retail customers is limited. The large number of customers and diversified customer base of residential, commercial, and industrial customers significantly reduces our credit risk. Contracts within the physical portfolio of power marketing and trading operations are primarily with traditional electric cooperatives and municipalities and other investor-owned utilities. At December 31, 2003, we believe the likelihood of significant losses associated with credit risk in our trade accounts receivable or physical power portfolio is remote.

(ii) Energy Trading Credit Risk Our extension of credit for energy marketing and trading is governed by a Corporate Credit Policy. Written guidelines document the management approval levels for credit limits, evaluation of creditworthiness, and credit risk mitigation procedures. We analyze net credit exposure and establish credit reserves based on the counterparties' credit rating, payment history, and tenor of the outstanding obligation. Exposures to credit risks are monitored daily by the Corporate Credit Risk function, which is independent of all trading operations. Energy commodity prices can be extremely volatile and the market can, at times, lack liquidity. Because of these issues, credit risk is generally greater than with other commodity trading.

The following tables provide information regarding our exposure on energy trading contracts as well as the expected maturities of those exposures. The tables include accounts receivable and energy risk management assets, which are net of accounts payable and energy risk management liabilities with the same counterparties when we have the right of offset. The credit collateral shown in the following tables includes cash and letters of credit.

(in thousands)

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Percent of Total Net Exposure	Net Exposure of Counterparties Greater than 10%
Investment Grade[1]	$472,173	$ 30,545	$441,628	78%	$–
Internally Rated-Investment Grade[2]	108,312	4,546	103,766	19	–
Non-Investment Grade	43,178	38,690	4,488	1	–
Internally Rated-Non-Investment Grade	48,944	35,671	13,273	2	–
Total	$672,607	$109,452	$563,155	100%	$–

(in thousands)

Rating	Maturity of Credit Risk Exposure: Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment Grade[1]	$425,675	$38,144	$8,354	$472,173
Internally Rated-Investment Grade[2]	108,312	–	–	108,312
Non-Investment Grade	43,178	–	–	43,178
Internally Rated-Non-Investment Grade	48,796	148	–	48,944
Total	$625,961	$38,292	$8,354	$672,607

(1) Includes counterparties rated Investment Grade or the counterparties' obligations are guaranteed or secured by an Investment Grade entity.

(2) Counterparties include a variety of entities, including investor-owned utilities, privately held companies, cities and municipalities. Cinergy assigns internal credit ratings to all counterparties within our credit risk portfolio, applying fundamental analytical tools. Included in this analysis is a review of (but not limited to) counterparty financial statements with consideration given to off-balance sheet obligations and assets, specific business environment, access to capital, and indicators from debt and equity capital markets.

(iii) Financial Derivatives Potential exposure to credit risk also exists from our use of financial derivatives such as interest rate swaps and treasury locks. Because these financial instruments are transacted with highly rated financial institutions, we do not anticipate nonperformance by any of the counterparties.

Risk Management We manage, on a portfolio basis, the market risks in our energy marketing and trading transactions subject to parameters established by our Risk Policy Committee. Our market and credit risks are monitored by the Global Risk Management function to ensure compliance with stated risk management policies and procedures. The Global Risk

Management function operates independently from the business units, which originate and actively manage the market risk exposures. Policies and procedures are periodically reviewed to assess their responsiveness to changing market and business conditions. Credit risk mitigation practices include requiring parent company guarantees, various forms of collateral, and the use of mutual netting/closeout agreements.

Exchange Rate Sensitivity

Cinergy has exposure to fluctuations in exchange rates between the U.S. dollar and the currencies of foreign countries where we have investments. When it is appropriate we will hedge our exposure to cash flow transactions, such as a dividend payment by one of our foreign subsidiaries.

Interest Rate Sensitivity

Our net exposure to changes in interest rates primarily consists of short-term debt instruments and certain pollution control debt. The following table reflects the different instruments used and the method of benchmarking interest rates, as of December 31, 2003:

(in millions)	Interest Benchmark	2003
Short-term Bank Loans/Commercial Paper	• Short-term Money Market • LIBOR(1)	$158
Pollution Control Debt	• Daily Market • Weekly Market • Auction Rate	193

(1) London Inter-Bank Offered Rate (LIBOR)

The weighted-average interest rates on the above instruments at December 31, were as follows:

	2003
Short-term Bank Loans/Commercial Paper	1.6%
Pollution Control Debt	1.4%

At December 31, 2003, forward yield curves project an increase in applicable short-term interest rates over the next five years.

The following table presents principal cash repayments, by maturity date and other selected information, for our long-term fixed-rate debt, other debt, and capital lease obligations as of December 31, 2003:

(in millions)

	Expected Maturity Date							
Liabilities	2004	2005	2006	2007	2008	There-after	Total	Fair Value
Long-term Debt(1)	$810	$202(4)(5)	$326	$366	$364	$2,169	$4,237	$4,465
Weighted-average interest rate(2)	6.3%	6.8%	6.7%	7.6%	6.5%	5.5%	6.0%	
Other(3)	$ 25	$ 20	$ 28	$361	$186	$ 164	$ 784	$ 882
Weighted-average interest rate(2)	6.9%	7.9%	7.0%	6.9%	6.4%	7.1%	6.8%	
Capital Leases								
Fixed-rate leases	$ 5	$ 6	$ 6	$ 6	$ 8	$ 24	$ 55	$ 55
Interest rate(2)	5.5%	5.5%	5.4%	5.4%	5.3%	4.9%	5.2%	

(1) Long-term debt includes amounts reflected as Long-term debt due within one year.

(2) The weighted-average interest rate is calculated as follows: (1) for Long-term Debt and Other, the weighted-average interest rate is based on the interest rates at December 31, 2003 of the debt that is maturing in the year reported and includes the effects of interest rate swaps that fix or float the interest payments differently from the stated rate; and (2) for Capital Leases, the weighted-average interest rate is based on the average interest rate of the lease payments made during the year reported.

(3) Long-term Debt related to investments under Cinergy Global Resources, Inc., Cinergy Investments Inc., and debt related to CC Funding Trust. See Note 3(B) of the Notes to Financial Statements for a discussion of the debt associated with this trust.

(4) Includes 6.50% Debentures due August 1, 2026, reflected as maturing in 2005, as the interest rate is due to reset on August 1, 2005.

(5) Includes 6.90% Debentures due June 1, 2025, reflected as maturing in 2005, as the debentures are putable to CG&E at the option of the holders on June 1, 2005.

Our current policy in managing exposure to fluctuations in interest rates is to maintain approximately 30 percent of the total amount of outstanding debt in floating interest rate debt instruments. In maintaining this level of exposure, we use interest rate swaps. Under the swaps, we agree with other parties to exchange, at specified intervals, the difference between fixed-rate and floating-rate interest amounts calculated on an agreed upon notional amount. CG&E has an outstanding interest rate swap agreement that decreased the percentage of floating-rate debt.

Under the provisions of the swap, which has a notional amount of $100 million, CG&E pays a fixed-rate and receives a floating-rate through October 2007. This swap qualifies as a cash flow hedge under the provisions of Statement 133. As the terms of the swap agreement mirror the terms of the debt agreement that it is hedging, we anticipate that this swap will continue to be effective as a hedge. Changes in fair value of this swap are recorded in *Accumulated other comprehensive income (loss)*, beginning with our adoption of Statement 133 on January 1, 2001. Cinergy Corp. has three outstanding interest rate swaps with a combined notional amount of $250 million. Under the provisions of the swaps, Cinergy Corp. will receive fixed-rate interest payments and pay floating-rate interest payments through September 2004. These swaps qualify as fair value hedges under the provisions of Statement 133. We anticipate that these swaps will continue to be effective as hedges. See Note 1(K) of the Notes to Financial Statements for additional information on financial derivatives. In the future, we will continually monitor market conditions to evaluate whether to modify our level of exposure to fluctuations in interest rates.

INFLATION

We believe that the recent inflation rates do not materially impact our financial condition. However, under existing regulatory practice, only the historical cost of plant is recoverable from customers. As a result, cash flows designed to provide recovery of historical plant costs may not be adequate to replace plant in future years.

ACCOUNTING MATTERS

Critical Accounting Policies

Preparation of financial statements and related disclosures in compliance with GAAP requires the use of assumptions and estimates. In certain instances, the application of GAAP requires judgments regarding future events, including the likelihood of success of particular initiatives, legal and regulatory challenges, and anticipated recovery of costs. Therefore, the possibility exists for materially different reported amounts under different conditions or assumptions. The following discusses relevant accounting policies and should be read in conjunction with the Notes to Financial Statements.

Fair Value Accounting for Energy Marketing and Trading We use fair value accounting for energy trading contracts, which is required, with certain exceptions, by Statement 133. We designate these contracts as either trading or non-trading at the time they are originated in accordance with EITF Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3). Short-term contracts used in our trading activities are generally priced using exchange based or over-the-counter price quotes. Long-term contracts typically must be valued using model pricing due to the lack of actively quoted prices. The period for which actively quoted prices are available varies by commodity and pricing point, but is generally shorter for electricity than gas. Use of model pricing requires estimation surrounding factors such as volatility and future price expectations beyond the actively quoted portion of the price curve. In addition, some contracts do not have fixed notional amounts and therefore must be valued using estimates of volumes to be consumed by the counterparty. See Changes in Fair Value for additional information.

We measure these risks by using complex valuation tools, both external and proprietary, which allow us to model prices for periods for which active quotes are unavailable. These models are dynamic and are continuously updated with the most recent data to improve estimates of future expectations. We measure risks for contracts that do not contain fixed notional amounts by obtaining historical data and projecting expected consumption. These models incorporate expectations surrounding the impacts that weather may play in future consumption. The results of these measures assist us in managing such risks within our portfolio. We also have a Global Risk Management function that is independent of the marketing and trading function and is under the oversight of a Risk Policy Committee comprised primarily of senior company executives. This group provides an independent evaluation of both forward price curves and the valuation of energy contracts. See Value at Risk for additional information.

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Fair value accounting has risk, including its application to short-term contracts, as gains and losses recorded through its use are not yet realized. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled. However, we monitor potential losses using VaR analysis. Our one-day VaR at December 31, 2003 was approximately $0.6 million.

For financial reporting purposes, assets and liabilities associated with energy trading transactions accounted for using fair value are reflected on the Balance Sheets as *Energy risk management assets current* and *non-current* and *Energy risk management liabilities current* and *non-current*, classified as current or non-current pursuant to each contract's tenor. Net gains and losses resulting from revaluation of contracts during the period are recognized currently in the Statements of Income.

Retail Customer Revenue Recognition Our retail revenues include amounts that are not yet billed to customers. Customers are billed throughout the month as both gas and electric meters are read. We recognize revenues for retail energy sales that have not yet been billed, but where gas or electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. In making our estimates of unbilled revenues we use complex systems that consider various factors, including weather, in our calculation of retail customer consumption at the end of each month. Given the use of these systems and the fact that customers are billed monthly, we believe it is unlikely that materially different results will occur in future periods when revenue is billed. Related receivables are sold under the accounts receivable sales agreement and therefore are not reflected on our Balance Sheets. See Note 1(D)*(i)* of the Notes to Financial Statements for additional information. The amount of unbilled revenues as of December 31, 2003, 2002, and 2001 were $176 million, $153 million, and $172 million, respectively.

Regulatory Accounting Our operating companies are regulated utility companies. Except with respect to the electric generation-related assets and liabilities of CG&E, the companies apply the provisions of Statement 71. In accordance with Statement 71, regulatory actions may result in accounting treatment different from that of non-rate regulated companies. The deferral of costs (as regulatory assets) or amounts provided in current rates to cover costs to be incurred in the future (as regulatory liabilities) may be appropriate when the future recovery or refunding of such costs is probable. In assessing probability, we consider such factors as regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be recognized in current period earnings. Our deferrals under the fuel adjustment clause recovery mechanism at PSI involve the use of estimates. Fuel costs, including purchased power when economically displacing fuel, must be allocated between PSI's retail customers and wholesale customers, with the lowest costs allocated to retail customers. This process is complex and involves the use of estimates that when finalized in future periods may result in adjustments to amounts deferred and collected from customers.

At December 31, 2003, regulatory assets totaled $595 million for CG&E (including $13 million for ULH&P) and $417 million for PSI. Current rates include the recovery of $587 million for CG&E (including $12 million for ULH&P) and $317 million for PSI. Of the $100 million not yet approved for recovery by PSI, $42 million relates to reorganization costs incurred in connection with the merger with CG&E. Deferral of these costs for inclusion in PSI's current rate case was previously authorized by the IURC. PSI has requested recovery of these costs in its pending rate case and a decision by the IURC is expected to be made in the first quarter of 2004. Should the IURC deny recovery of those costs, a charge to current period earnings would be required. In addition to the regulatory assets, CG&E and PSI have regulatory liabilities totaling $155 million (including $27 million for ULH&P) and $336 million at December 31, 2003, respectively. See Note 1(C) of the Notes to Financial Statements for additional detail regarding regulatory assets and regulatory liabilities.

Pension and Other Postretirement Benefits Our reported costs of providing pension and other postretirement benefits (as described in Note 9 of the Notes to Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs associated with our defined benefit pension plans, for example, are impacted by employee demographics (including age, compensation levels, and employment periods), the level of contributions we make to the plan, and earnings on plan assets. Changes made to the provisions of the plan may impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

In accordance with Statement of Financial Accounting Standards No. 87, *Employers' Accounting for Pensions* (Statement 87), changes in pension obligations associated with the above factors may not be immediately recognized as pension costs on the Statements of Income, but may be deferred and amortized in the future over the average remaining service period of active plan participants to the extent that Statement 87 recognition provisions are triggered. For the years ended December 31, 2003, 2002, and 2001, we recorded pension costs for our defined benefit pension plans (including early retirement program costs recognized in accordance with Statement of Financial Accounting Standards No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits* (Statement 88)) of approximately $62 million, $68 million, and $32 million, respectively.

Our pension plan assets are principally comprised of equity and debt investments. Differences between actual portfolio returns and expected returns may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

In selecting our discount rate assumption, we considered rates of return on high-quality corporate debt instruments that are expected to be available through the maturity dates of the pension benefits. Our expected long-term rate of return on plan assets is based on a calculation provided by an independent investment-consulting firm. Our expected long-term rate of return on pension plan assets is based on our targeted asset allocation assumption of 60 percent equity investments and

40 percent debt investments. Our 60 percent equity investment target includes allocations to domestic, developed international, and emerging markets equities. Our asset allocation is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective. We regularly review our asset allocation and periodically rebalance our investments to our targeted allocation as appropriate.

We base our determination of pension cost on a market-related valuation of assets that reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual fair value of assets.

Based on our assumed long-term rate of return of 8.5 percent, discount rate of 6.25 percent, and various other assumptions, we estimate that our pension costs associated with our defined benefit pension plans will increase from $53 million (excluding Statement 88 costs) in 2003 to approximately $66 million in 2004. Modifying the expected long-term rate of return on our pension plan assets by .25 percent, and holding all other assumptions constant, would change 2004 pension costs by approximately $2 million. Lowering the discount rate assumption by .25 percent, and holding all other assumptions constant, would change 2004 pension costs by approximately $5 million.

Other postretirement benefit costs are impacted by employee demographics, per capita claims costs, and health care cost trend rates. Other postretirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including the discount rates used in determining the accumulated postretirement benefit obligation and the postretirement benefit costs. In accordance with Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (Statement 106), changes in postretirement benefit obligations associated with these factors may not be immediately recognized as postretirement benefit costs but may be deferred and amortized in the future over the average remaining service period of active plan participants to the extent that Statement 106 recognition provisions are triggered. For the years ended December 31, 2003, 2002, and 2001, we recorded other postretirement benefit costs of approximately $35 million, $29 million, and $27 million, respectively, in accordance with the provisions of Statement 106. Based upon a discount rate of 6.25 percent and various other assumptions, we estimate that our other postretirement benefit costs will increase from $35 million in 2003 to approximately $38 million in 2004.

See Note 9 of the Notes to Financial Statements for information on the effects of FASB Staff Position 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.*

Income Taxes Management judgment is required in developing our provision for income taxes, including the determination of deferred tax assets, liabilities and any valuation allowances recorded against the deferred tax assets. We evaluate quarterly the realizability of our deferred tax assets by assessing our valuation allowance and adjusting the amount of such allowance, if necessary. The factors used to assess the likelihood of realization are our forecast of future taxable income and the availability of tax planning strategies that can be implemented to realize deferred tax assets. Failure to achieve forecasted taxable income might affect the ultimate realization of deferred tax assets.

Legal and Environmental Contingencies When it is probable that an environmental or other legal liability has been incurred, a loss is recognized assuming the amount of the loss can be reasonably estimated. Estimates of the probability and the amount of loss are often made based on currently available facts, present laws and regulations, and consultation with third-party experts. Accounting for contingencies requires significant judgment by management regarding the estimated probabilities and ranges of exposure to potential liability. Management's assessment of our exposure to contingencies could change to the extent there are additional future developments, administrative actions, or as more information becomes available. If actual legal obligations are materially different from our estimates, the recognition of the actual amounts may have a material impact on our results of operations and financial position.

Impairment of Long-lived Assets Current accounting standards require long-lived assets be measured for impairment whenever indicators of impairment exist. If deemed impaired under the standards, assets are written down to fair value with a charge to current period earnings. As a producer of electricity, Cinergy and its operating companies are owners of generating plants, which are largely coal-fired. At December 31, 2003, the carrying value of these generating plants is $5 billion. As a result of the various emissions and by-products of coal consumption, the companies are subject to extensive environmental regulations and are currently subject to a number of environmental contingencies. See Note 1(I) of the Notes to Financial Statements for additional information. While we cannot predict the potential affect the resolution of these matters will have on our financial position or results of operations, we believe that the carrying values of these assets are recoverable. In making this assessment, we consider such factors as the expected ability to recover additional investment in environmental compliance expenditures, the relative pricing of wholesale electricity in the region, the anticipated demand, and the cost of fuel. We will continue to evaluate these assets for impairment when events or circumstances indicate the carrying value may not be recoverable.

Accounting Changes

Energy Trading In October 2002, the EITF reached consensus in EITF 02-3, to (a) rescind EITF 98-10, (b) generally preclude the recognition of gains at the inception of new derivatives, and (c) require all realized and unrealized gains and losses on energy trading derivatives to be presented net in the Statements of Income, whether or not settled physically.

The consensus to rescind EITF 98-10 required all energy trading contracts that do not qualify as derivatives to be accounted for on an accrual basis, rather than at fair value. The consensus was immediately effective for all new contracts executed after October 25, 2002, and required a cumulative effect adjustment to income, net of tax, on January 1, 2003, for all contracts executed on or prior to October 25, 2002. The cumulative effect adjustment, on a net of tax basis, was a loss of approximately $13 million, which primarily includes the impact of certain coal contracts, gas inventory, and certain gas contracts, which are accounted for at fair value. We expect this rescission to have the largest ongoing impact on our gas trading business, which uses financial contracts, physical contracts, and gas inventory to take advantage of various arbitrage opportunities. Prior to the rescission of EITF 98-10, all of these activities were accounted for at fair value. Under the revised guidance, only certain items are accounted for at fair value, which could increase inter-period volatility in reported results of operations. As a result, we began applying fair value hedge accounting in June 2003 to certain quantities of gas inventory (more fully discussed in Note 1(K)*(i)* of the Notes to Financial Statements) and are further reviewing additional applications for hedge accounting.

The consensus to require all gains and losses on energy trading derivatives to be presented net in the Statements of Income was effective January 1, 2003, and required reclassification for all periods presented. This resulted in substantial reductions in reported *Operating Revenues*, *Fuel and purchased and exchanged power* expense, and *Gas purchased* expense. However, *Operating Income* and *Net Income* were not affected by this change.

Derivatives In May 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (Statement 149). Statement 149 primarily amends Statement 133 to incorporate implementation conclusions previously cleared by the FASB staff, to clarify the definition of a derivative and to require derivative instruments that include up-front cash payments to be classified as a financing activity in the Statements of Cash Flows. Implementation issues previously cleared by the FASB staff were effective at the time they were cleared and new guidance was effective in the third quarter of 2003. In connection with our adoption, we reviewed certain power purchase or sale contracts to determine if they met the revised normal purchases and sales scope exception criteria in Statement 149. If these criteria were not met, the contract was adjusted to fair value. The impact of adopting Statement 149 was not material to our financial position or results of operations.

In June 2003, the FASB issued final guidance on the use of broad market indices (e.g., consumer price index) in power purchases and sales contracts. This guidance clarifies that the normal purchases and sales scope exception is precluded if a contract contains a broad market index that is not clearly and closely related to the asset being sold or purchased (or a direct factor in the production of the asset sold or purchased). The guidance provides criteria that must be met for the index to be considered clearly and closely related. This guidance, which was effective in the fourth quarter of 2003, was not material to our financial position or results of operations.

Asset Retirement Obligations In July 2001, the FASB issued Statement 143, which requires fair value recognition beginning January 1, 2003, of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred. Statement 143 prohibits the accrual of estimated retirement and removal costs unless resulting from legal obligations. Our accounting policy for such legal obligations and for accrued cost of removal of our rate regulated long-lived assets is described in Note 1(J) of the Notes to Financial Statements.

We adopted Statement 143 on January 1, 2003, and recognized a gain of $39 million (net of tax) for the cumulative effect of this change in accounting principle. Substantially all of this adjustment reflects the reversal of previously accrued cost of removal for CG&E's generating assets, which do not apply the provisions of Statement 71. *Accrued cost of removal* at adoption included $462 million of accumulated cost of removal related to our operating companies' utility plant in service assets, which represent regulatory liabilities after adoption and were not included as part of the cumulative effect adjustment. The increases in assets and liabilities from adopting Statement 143 were not material to our financial position.

Pro-forma results as if Statement 143 was applied retroactively for the years ended December 31, 2002 and 2001, are not materially different from reported results.

Consolidation of VIEs In January 2003, the FASB issued Interpretation 46, which significantly changes the consolidation requirements for traditional special purpose entities (SPE) and certain other entities subject to its scope. This interpretation defines a VIE as (a) an entity that does not have sufficient equity to support its activities without additional financial support or (b) an entity that has equity investors that do not have voting rights or do not absorb losses or receive returns. These entities must be consolidated when certain criteria are met. The interpretation was originally to be effective as of

July 1, 2003 for Cinergy; however, the FASB subsequently permitted deferral of the effective date to December 31, 2003 for traditional SPEs and to March 31, 2004 for all other entities subject to the scope of Interpretation 46. During this deferral period, the FASB clarified and amended several provisions, much of which is intended to assist in the application of Interpretation 46 to operating entities. Clarifications were not needed for most traditional SPEs and we therefore elected to implement Interpretation 46 for such entities, as discussed below, in accordance with the original implementation date of July 1, 2003. Prior period financial statements were not restated for these changes.

Interpretation 46 required us to consolidate two SPEs that have individual power sale agreements to Central Maine Power Company. Further, we were no longer permitted to consolidate a trust that was established by Cinergy Corp. in 2001 to issue approximately $316 million of combined preferred trust securities and stock purchase contracts. For further information on the accounting for these entities see Note 3 of the Notes to Financial Statements.

We have concluded that our accounts receivable sale facility, as discussed in Note 3(C) of the Notes to Financial Statements, will remain unconsolidated since it involves transfers of financial assets to a qualifying SPE, which is exempted from consolidation by Interpretation 46 and Statement 140.

We are continuing to evaluate the impact of Interpretation 46 on several operating joint ventures, primarily involved in cogeneration and energy efficiency operations, that we currently do not consolidate. If all these entities were consolidated, their total assets of approximately $590 million (the majority of which is non-current) and total liabilities of approximately $210 million (which includes long-term debt of approximately $90 million) would be recognized on our Balance Sheets. Our current investment in these entities is approximately $200 million. We also guarantee certain performance obligations of these entities with an estimated maximum potential exposure of approximately $40 million, as disclosed in Note 11(C)*(vii)* of the Notes to Financial Statements. If any of these entities are required to be consolidated, they will be included in the March 31, 2004 consolidated financial statements.

Financial Instruments with Characteristics of Both Liabilities and Equity In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* (Statement 150). Statement 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. This statement was effective for financial instruments entered into or modified after May 31, 2003, and was effective on July 1, 2003, for financial instruments held prior to issuance of this statement. Statement 150 would have required Cinergy Corp.'s preferred trust securities to be reported as a liability; however, as described more fully in Note 3(B) of the Notes to Financial Statements, the trust holding these securities is no longer permitted to be consolidated and the preferred trust securities are no longer reported on our Balance Sheets. However, our note payable to the trust is recorded on the Balance Sheets as *Long-term debt*. As a result, the impact of adopting Statement 150 was not material to our financial position or results of operations.

As discussed in Note 3(B) of the Notes to Financial Statements, Cinergy Corp. issued forward stock sale contracts that require purchase by the holder of a certain number of Cinergy Corp. shares in February 2005 (stock contracts). The number of shares to be issued is contingent on the market price of Cinergy Corp. stock, but subject to a predetermined ceiling and floor price. In October 2003, the FASB staff released an interpretation of Statement 150 that requires an evaluation of these stock contracts to determine whether they constitute a liability, with any changes in accounting required in January 2004. This interpretation did not have any impact on our current accounting.

Other Matters

Voluntary Early Retirement Programs (VERP) As a result of the employees accepting a VERP in 2002, we recorded expenses of approximately $43 million. During 2003, we offered a VERP and other severance benefits (Severance Programs) to certain non-union and union employees. As a result of the employees electing the Severance Programs, we recorded expenses of approximately $14 million during 2003.

Synthetic Fuel Production In July 2002, we acquired a coal-based synthetic fuel production facility. As of December 31, 2003, our net book value in this facility was approximately $60 million. The synthetic fuel produced at this facility qualifies for tax credits in accordance with Section 29 of the Internal Revenue Code. Eligibility for these credits expires after 2007. We received a private letter ruling from the Internal Revenue Service (IRS) in connection with the acquisition of the facility. To date, we have produced and sold approximately 4.4 million tons of synthetic fuel at this facility, resulting in approximately $120 million in tax credits, including approximately $80 million in 2003.

In the second quarter of 2003, the IRS announced, as a result of an audit of another taxpayer, that it had reason to question and was reviewing the scientific validity of test procedures and results that were presented as evidence the fuel underwent a significant chemical change. The IRS recently announced that it has finished its review and has determined that test procedures and results used by taxpayers may be scientifically valid if the procedures are applied in a consistent and unbiased manner. The IRS also announced that it plans to impose new testing and record-keeping requirements on synthetic fuel producers and plans to issue guidance extending these requirements to taxpayers already holding private letter rulings on the issue of significant chemical change. We believe that any new testing or record-keeping requirements imposed by the IRS will not have a material effect on our financial position or results of operations.

Patents Ronald A. Katz Technology Licensing, L.P. (RAKTL) has offered us a license to a portfolio of patents claiming that the patents may be infringed by certain products and services utilized by us. The patents purportedly relate to various aspects of telephone call processing in Cinergy call centers. As of this date, no legal proceedings have been instituted against us, but if the RAKTL patents are valid, enforceable and apply to our business, we could be required to seek a license from RAKTL or to discontinue certain activities. We are currently considering this matter, but lack sufficient information to assess the potential outcome at this time.

PUCO Review of Financial Condition of Ohio Regulated Utilities In October 2002, as the result of financial problems experienced by certain public utility companies and the existing state of the economy, the PUCO issued an order initiating a review of, and requesting comments with respect to, the financial condition of the 19 large public utilities (gas, electric, and telecommunication) serving Ohio customers, including CG&E. The PUCO intends to identify available measures to ensure that the regulated operations of the Ohio public utilities are not adversely impacted by the parent or affiliate companies' non-regulated operations. CG&E filed comments stating that the PUCO has sufficient authority to adequately regulate the financial condition of public utilities. In January 2004, the PUCO staff filed their recommendations on the measures to be used to address the PUCO's concerns, focusing on such areas as dividend distributions, cost of capital, and restrictions on non-regulated investments, loans, and guarantees. CG&E cannot predict the outcome of this matter at this time.

Energy Market Investigations In July 2003, we received a subpoena from the Commodity Futures Trading Commission (CFTC). As has been previously reported by the press, the CFTC has served subpoenas on numerous other energy companies. The CFTC request sought certain information regarding our trading activities, including price reporting to energy industry publications. The CFTC sought particular information concerning these matters for the period May 2000 through January 2001 as to one of our employees. Based on an initial review of these matters, we placed that employee on administrative leave and have subsequently terminated his employment. We are continuing an investigation of these matters, including whether price reporting inconsistencies occurred in our operations, and have been cooperating fully with the CFTC.

In August 2003, Cinergy, along with 38 other companies, was named as a defendant in civil litigation filed as a purported class action on behalf of all persons who purchased and/or sold New York Mercantile Exchange natural gas futures and options contracts between January 1, 2000 and December 31, 2002. The complaint alleges that improper price reporting caused damages to the class. Two similar lawsuits have subsequently been filed, and these three lawsuits have been consolidated for pretrial purposes. Plaintiffs filed a consolidated class action complaint in January 2004. We believe this action is without merit and intend to defend this lawsuit vigorously; however, we cannot predict the outcome of this matter at this time.

In the second quarter of 2003, we received initial and follow-up third-party subpoenas from the SEC requesting information related to particular trading activity with one of our counterparties who was the target of an investigation by the SEC. We have fully cooperated with the SEC in connection with this matter. In January 2004, we received a grand jury subpoena from the Assistant United States Attorney in the Southern District of Texas for information relating to the same trading activities being investigated by the SEC. Specifically, the Assistant United States Attorney has requested information relating to communications between a former employee and another energy company. We understand that we are neither a target nor are we under investigation by the Department of Justice in relation to these communications.

At this time, it is not possible to predict the outcome of these investigations and litigation or their impact on our financial position or results of operations; although, in the opinion of management, they are not likely to have a material adverse effect on our financial position or results of operations.

CONSOLIDATED STATEMENTS OF INCOME

(dollars in thousands, except per share amounts)	2003	2002	2001
Operating Revenues (Note 1(Q)*(i)*)			
Electric	$3,383,132	$3,338,068	$3,215,652
Gas	835,507	590,471	655,678
Other	197,238	130,813	78,246
Total Operating Revenues	4,415,877	4,059,352	3,949,576
Operating Expenses			
Fuel and purchased and exchanged power (Note 1(Q)*(i)*)	1,158,196	989,699	1,014,571
Gas purchased (Note 1(Q)*(i)*)	503,834	309,983	397,310
Operation and maintenance	1,276,453	1,291,589	1,008,133
Depreciation	419,098	405,487	366,648
Taxes other than income taxes	249,746	263,002	227,652
Total Operating Expenses	3,607,327	3,259,760	3,014,314
Operating Income	808,550	799,592	935,262
Equity in Earnings of Unconsolidated Subsidiaries	15,201	15,261	1,494
Miscellaneous Income — Net	38,156	12,402	40,404
Interest Expense	268,602	243,099	258,723
Preferred Dividend Requirement of Subsidiary Trust (Note 3(B))	11,940	23,832	1,067
Income Before Taxes	581,365	560,324	717,370
Income Taxes (Note 10)	143,508	160,255	257,308
Preferred Dividend Requirements of Subsidiaries	3,433	3,433	3,433
Income Before Discontinued Operations and Cumulative Effect of Changes in Accounting Principles	434,424	396,636	456,629
Discontinued operations, net of tax (Note 14)	8,886	(25,161)	(14,350)
Cumulative effect of changes in accounting principles, net of tax (Note 1(Q)*(vi)*)	26,462	(10,899)	–
Net Income	$ 469,772	$ 360,576	$ 442,279
Average Common Shares Outstanding	176,535	167,047	159,110
Earnings Per Common Share (Note 16)			
Income Before Discontinued Operations and Cumulative Effect of Changes in Accounting Principles	$ 2.46	$ 2.37	$ 2.87
Discontinued operations, net of tax	0.05	(0.15)	(0.09)
Cumulative effect of changes in accounting principles, net of tax	0.15	(0.06)	–
Net Income	$ 2.66	$ 2.16	$ 2.78
Earnings Per Common Share — Assuming Dilution (Note 16)			
Income Before Discontinued Operations and Cumulative Effect of Changes in Accounting Principles	$ 2.43	$ 2.34	$ 2.84
Discontinued operations, net of tax	0.05	(0.15)	(0.09)
Cumulative effect of changes in accounting principles, net of tax	0.15	(0.06)	–
Net Income	$ 2.63	$ 2.13	$ 2.75
Dividends Declared Per Common Share	$ 1.84	$ 1.80	$ 1.80

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

CONSOLIDATED BALANCE SHEETS

ASSETS

(dollars in thousands)	DECEMBER 31 2003	2002
Current Assets		
Cash and cash equivalents	$ 169,120	$ 200,112
Restricted deposits (Note 6)	92,813	3,092
Notes receivable, current (Note 5)	189,854	135,873
Accounts receivable less accumulated provision for doubtful accounts of $7,884 at December 31, 2003, and $16,368 at December 31, 2002 (Note 3(C))	1,074,518	1,280,810
Materials, supplies, and fuel (Note 1(G))	321,658	319,454
Energy risk management current assets (Note 1(K)*(i)*)	305,058	464,028
Prepayments and other	89,576	107,086
Total Current Assets	2,242,597	2,510,455
Property, Plant, and Equipment — at Cost		
Utility plant in service (Note 19)	9,732,123	8,669,045
Construction work in progress	275,459	469,300
Total Utility Plant	10,007,582	9,138,345
Non-regulated property, plant, and equipment (Note 19)	4,527,943	4,667,940
Accumulated depreciation (Note 1(Q)*(iii)*)	4,908,019	4,639,713
Net Property, Plant, and Equipment	9,627,506	9,166,572
Other Assets		
Regulatory assets (Note 1(C))	1,012,151	1,022,696
Investments in unconsolidated subsidiaries	494,520	417,188
Energy risk management non-current assets (Note 1(K)*(i)*)	97,334	162,773
Notes receivable, non-current (Note 5)	213,853	-
Other investments	184,044	163,851
Goodwill	43,717	43,717
Other intangible assets	1,632	2,059
Other	197,351	195,867
Total Other Assets	2,244,602	2,008,151
Assets of Discontinued Operations (Note 14)	4,501	147,265
Total Assets	$14,119,206	$13,832,443

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

LIABILITIES AND SHAREHOLDERS' EQUITY

(dollars in thousands)	DECEMBER 31 2003	2002
Current Liabilities		
Accounts payable	$ 1,240,423	$ 1,318,379
Accrued taxes	217,993	258,613
Accrued interest	68,952	62,244
Notes payable and other short-term obligations (Note 6)	351,412	667,973
Long-term debt due within one year	839,103	176,000
Energy risk management current liabilities (Note 1(K)*(i)*)	296,122	407,710
Other	107,438	105,026
Total Current Liabilities	3,121,443	2,995,945
Non-Current Liabilities		
Long-term debt (Note 4)	4,131,909	4,011,568
Deferred income taxes (Note 10)	1,557,981	1,458,171
Unamortized investment tax credits	108,884	118,095
Accrued pension and other postretirement benefit costs (Note 9)	662,834	626,167
Accrued cost of removal (Note 1(C))	490,856	525,415
Energy risk management non-current liabilities (Note 1(K)*(i)*)	64,861	143,991
Other	205,344	179,767
Total Non-Current Liabilities	7,222,669	7,063,174
Liabilities of Discontinued Operations (Note 14)	11,594	108,833
Commitments and Contingencies (Note 11)		
Total Liabilities	10,355,706	10,167,952
Preferred Trust Securities (Note 3(B))		
Company obligated, mandatorily redeemable, preferred trust securities of subsidiary, holding solely debt securities of the company	–	308,187
Cumulative Preferred Stock of Subsidiaries		
Not subject to mandatory redemption	62,818	62,828
Common Stock Equity (Note 2)		
Common Stock — $.01 par value; authorized shares — 600,000,000; issued shares — 178,438,369 at December 31, 2003, and 168,663,115 at December 31, 2002; outstanding shares — 178,336,854 at December 31, 2003, and 168,663,115 at December 31, 2002	1,784	1,687
Paid-in capital	2,195,985	1,918,136
Retained earnings	1,551,003	1,403,453
Treasury shares at cost — 101,515 shares at December 31, 2003	(3,255)	–
Accumulated other comprehensive income (loss) (Note 18)	(44,835)	(29,800)
Total Common Stock Equity	3,700,682	3,293,476
Total Liabilities and Shareholders' Equity	$14,119,206	$13,832,443

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

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(dollars in thousands)	COMMON STOCK	PAID-IN CAPITAL	RETAINED EARNINGS	TREASURY STOCK	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TOTAL COMMON STOCK EQUITY
2001						
Beginning balance (158,967,661 shares)	$1,590	$1,619,153	$1,179,113	$ –	$(10,895)	$2,788,961
Comprehensive income:						
Net income			442,279			442,279
Other comprehensive income (loss), net of tax effect of $1,454 (Note 18)						
Foreign currency translation adjustment (Note 1(R))					1,641	1,641
Minimum pension liability adjustment					(1,555)	(1,555)
Unrealized gain (loss) on investment trusts					(841)	(841)
Cumulative effect of change in accounting principle					(2,500)	(2,500)
Cash flow hedges (Note 1(K)*(ii)*)					(2,779)	(2,779)
Total comprehensive income						436,245
Issuance of common stock — net (435,178 shares)	4	9,896				9,900
Treasury shares purchased (344,034 shares)		(10,015)				(10,015)
Treasury shares reissued (344,034 shares)		9,157				9,157
Dividends on common stock ($1.80 per share)			(286,289)			(286,289)
Stock purchase contracts (Note 2(E))		(23,200)				(23,200)
Other		14,668	2,032			16,700
Ending balance (159,402,839 shares)	$1,594	$1,619,659	$1,337,135	$ –	$(16,929)	$2,941,459
2002						
Comprehensive income:						
Net income			360,576			360,576
Other comprehensive income (loss), net of tax effect of $11,509 (Note 18)						
Foreign currency translation adjustment, net of reclassification adjustments (Note 1(R))					25,917	25,917
Minimum pension liability adjustment					(13,763)	(13,763)
Unrealized gain (loss) on investment trusts					(5,277)	(5,277)
Cash flow hedges (Note 1(K)*(ii)*)					(19,748)	(19,748)
Total comprehensive income						347,705
Issuance of common stock — net (9,260,276 shares)	93	267,768				267,861
Dividends on common stock ($1.80 per share)			(298,292)			(298,292)
Other		30,709	4,034			34,743
Ending balance (168,663,115 shares)	$1,687	$1,918,136	$1,403,453	$ –	$(29,800)	$3,293,476
2003						
Comprehensive income:						
Net income			469,772			469,772
Other comprehensive income (loss), net of tax effect of $11,700 (Note 18)						
Foreign currency translation adjustment, net of reclassification adjustments (Note 1(R))					10,528	10,528
Minimum pension liability adjustment					(33,846)	(33,846)
Unrealized gain (loss) on investment trusts					6,757	6,757
Cash flow hedges (Note 1(K)*(ii)*)					1,526	1,526
Total comprehensive income						454,737
Issuance of common stock — net (9,775,254 shares)	97	269,977				270,074
Treasury shares purchased (101,515 shares)				(3,255)		(3,255)
Dividends on common stock ($1.84 per share)			(322,371)			(322,371)
Other		7,872	149			8,021
Ending balance (178,336,854 shares)	$1,784	$2,195,985	$1,551,003	$(3,255)	$(44,835)	$3,700,682

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(dollars in thousands)	2003	2002	2001
Cash Flows from Continuing Operations			
Operating Activities			
Net income	$ 469,772	$ 360,576	$ 442,279
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation	419,098	405,487	366,648
(Income) Loss of discontinued operations, net of tax	(8,886)	25,161	14,350
(Income) Loss on sale of investment in unconsolidated subsidiaries	(93)	(16,518)	-
Cumulative effect of changes in accounting principles, net of tax	(26,462)	10,899	-
Change in net position of energy risk management activities	(11,723)	(43,202)	(96,850)
Deferred income taxes and investment tax credits — net	85,108	148,069	118,544
Equity in (earnings) losses of unconsolidated subsidiaries	(15,201)	(15,261)	(1,494)
Allowance for equity funds used during construction	(7,532)	(12,861)	(8,628)
Regulatory assets deferrals	(83,228)	(110,867)	(141,324)
Regulatory assets amortization	90,476	116,512	119,344
Accrued pension and other postretirement benefit costs	36,667	127,366	34,246
Deferred cost under gas recovery mechanism	(19,335)	(23,373)	53,374
Cost of removal	(16,598)	-	-
Changes in current assets and current liabilities:			
Restricted deposits	(9,382)	969	(3,561)
Accounts and notes receivable	123,504	(235,437)	495,295
Materials, supplies, and fuel	(2,059)	(83,585)	(81,269)
Prepayments	8,859	(26,818)	13,507
Accounts payable	(89,149)	311,339	(465,034)
Accrued taxes and interest	(35,510)	65,019	(40,345)
Other assets	(13,157)	(49,259)	(19,925)
Other liabilities	50,504	1,586	(75,467)
Net cash provided by (used in) operating activities	945,673	955,802	723,690
Financing Activities			
Change in short-term debt	(312,747)	(442,469)	15,339
Issuance of long-term debt	688,166	628,170	872,930
Issuance of preferred trust securities	-	-	306,327
Redemption of long-term debt	(487,901)	(112,578)	(90,448)
Funds on deposit from issuance of debt securities	(80,339)	-	-
Retirement of preferred stock of subsidiaries	(10)	(3)	(1)
Issuance of common stock	270,074	267,861	9,900
Dividends on common stock	(322,371)	(298,292)	(286,289)
Net cash provided by (used in) financing activities	(245,128)	42,689	827,758
Investing Activities			
Construction expenditures (less allowance for equity funds used during construction)	(704,117)	(853,332)	(832,693)
Proceeds from notes receivable	9,187	-	-
Acquisitions and other investments	(87,859)	(118,375)	(701,833)
Proceeds from sale of subsidiaries and equity investments	51,252	86,071	-
Net cash provided by (used in) investing activities	$(731,537)	$(885,636)	$(1,534,526)

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
(CONTINUED)

(dollars in thousands)	2003	2002	2001
Net increase (decrease) in cash and cash equivalents from continuing operations	$(30,992)	$112,855	$ 16,922
Cash and cash equivalents from continuing operations at beginning of period	200,112	87,257	70,335
Cash and cash equivalents from continuing operations at end of period	$169,120	$200,112	$ 87,257
Cash Flows from Discontinued Operations			
Operating activities	$ (5,871)	$ 40,397	$ (5,841)
Financing activities	(14,898)	(39,464)	39,505
Investing activities	(202)	(3,772)	(32,573)
Net increase (decrease) in cash and cash equivalents from discontinued operations	(20,971)	(2,839)	1,091
Cash and cash equivalents from discontinued operations at beginning of period	20,971	23,810	22,719
Cash and cash equivalents from discontinued operations at end of period	$ –	$ 20,971	$ 23,810
Supplemental Disclosure of Cash Flow Information			
Cash paid during the year for:			
Interest (net of amount capitalized)	$263,228	$253,266	$271,323
Income taxes	$ 92,175	$ 57,739	$153,092

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

	DECEMBER 31	
(dollars in thousands)	2003	2002
Long-term Debt (excludes current portion)		
Cinergy Corp.		
Other Long-term Debt:		
6.53 % Debentures due December 16, 2008	$200,000	$200,000
6.125% Debentures due April 15, 2004	–	200,000
6.25 % Debentures due September 1, 2004 (Executed interest rate swaps of $250 million set at London Inter-Bank Offered Rate (LIBOR) plus 2.44%)	–	512,554
6.90 % Note Payable due February 16, 2007 (Note 4)	326,032	–
Total Other Long-term Debt	526,032	912,554
Unamortized Premium and Discount — Net	(6,080)	(165)
Total — Cinergy Corp.	519,952	912,389
Cinergy Global Resources, Inc.		
Other Long-term Debt:		
6.20 % Debentures due November 3, 2008	150,000	150,000
Variable interest rate of EURIBOR plus 1.2%, maturing November 2016	79,104	63,675
Total Other Long-term Debt	229,104	213,675
Unamortized Premium and Discount — Net	(160)	(193)
Total — Cinergy Global Resources, Inc.	228,944	213,482
Cinergy Investments, Inc.		
Other Long-term Debt:		
9.23 % Notes Payable, due November 5, 2016 (Note 4)	107,142	–
7.81 % Notes Payable, due June 1, 2009 (Note 4)	93,041	–
Other	3,547	–
Total — Cinergy Investments, Inc.	$203,730	$ –

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

(dollars in thousands)	DECEMBER 31 2003	2002
The Cincinnati Gas & Electric Company (CG&E) and subsidiaries		
First Mortgage Bonds:		
6.45 % Series due February 15, 2004	$ –	$ 110,000
7.20 % Series due October 1, 2023	–	265,500
5.45 % Series due January 1, 2024 (Pollution Control)	46,700	46,700
5½ % Series due January 1, 2024 (Pollution Control)	48,000	48,000
Total First Mortgage Bonds	94,700	470,200
Other Long-term Debt:		
Liquid Asset Notes with Coupon Exchange due October 1, 2007 (Executed interest rate swap to fix the rate at 6.87% through maturity)	100,000	100,000
6.40 % Debentures due April 1, 2008	100,000	100,000
6.90 % Debentures due June 1, 2025 (Redeemable at the option of the holders on June 1, 2005)	150,000	150,000
8.28 % Junior Subordinated Debentures due June 30, 2025	–	100,000
5.70 % Debentures due September 15, 2012, effective interest rate of 6.42%	500,000	500,000
5.40 % Debentures due June 15, 2033, effective interest rate of 6.90%	200,000	–
5⅜ % Debentures due June 15, 2033	200,000	–
Series 2002A, Ohio Air Quality Development Revenue Refunding Bonds, due September 1, 2037 (Pollution Control)	42,000	42,000
Series 2002B, Ohio Air Quality Development Revenue Refunding Bonds, due September 1, 2037 (Pollution Control)	42,000	42,000
Series 1992A, 6.50% Collateralized Pollution Control Revenue Refunding Bonds, due November 15, 2002	12,721	12,721
Total Other Long-term Debt	1,346,721	1,046,721
Unamortized Premium and Discount — Net	(37,299)	(1,861)
Total CG&E Long-term Debt	1,404,122	1,515,060
The Union Light, Heat and Power Company		
Other Long-term Debt:		
6.50 % Debentures due April 30, 2008	20,000	20,000
7.65 % Debentures due July 15, 2025	15,000	15,000
7.875% Debentures due September 15, 2009	20,000	20,000
Total Other Long-term Debt	55,000	55,000
Unamortized Premium and Discount — Net	(315)	(347)
Total ULH&P Long-term Debt	54,685	54,653
Total CG&E Consolidated Long-term Debt	$1,458,807	$1,569,713
PSI Energy, Inc. (PSI)		
First Mortgage Bonds:		
Series ZZ, 5¾ % due February 15, 2028 (Pollution Control)	$ 50,000	$ 50,000
Series AAA, 7⅛ % due February 1, 2024	30,000	30,000
Series BBB, 8.0 % due July 15, 2009	124,665	124,665
Series CCC, 8.85 % due January 15, 2022	53,055	53,055
Series DDD, 8.31 % due September 1, 2032	38,000	38,000
Series EEE, 6.65 % due June 15, 2006	325,000	325,000
Total First Mortgage Bonds	620,720	620,720
Secured Medium-term Notes:		
Series A, 8.55% to 8.57% as of December 31, 2003; 8.37% to 8.81% as of December 31, 2002. Due November 8, 2006 to June 1, 2022	7,500	34,300
Series B, 6.37% to 8.24%, due August 15, 2008 to August 22, 2022 (Series A and B, 7.255% weighted average interest rate as of December 31, 2003; 7.623% weighted average interest rate as of December 31, 2002. 10.1 and 13.9 year weighted average remaining life at December 31, 2003 and 2002, respectively)	70,000	70,000
Total Secured Medium-term Notes	$ 77,500	$ 104,300

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION
(CONTINUED)

(dollars in thousands)	DECEMBER 31 2003	2002
PSI Energy, Inc. (PSI)		
Other Long-term Debt:		
Indiana Development Finance Authority Environmental Refunding Revenue Bonds, due May 1, 2035	$ 44,025	$ 44,025
Indiana Development Finance Authority Environmental Refunding Revenue Bonds, due April 1, 2022	10,000	10,000
6.35% Debentures due November 15, 2006	50	50
6.50% Synthetic Putable Yield Securities due August 1, 2026 (Interest rate resets August 1, 2005)	50,000	50,000
7.25% Junior Maturing Principal Securities due March 15, 2028	2,658	2,658
6.00% Rural Utilities Service Obligation payable in annual installments	80,988	82,025
6.52% Senior Notes due March 15, 2009	97,342	97,342
7.85% Debentures due October 15, 2007	265,000	265,000
5.00% Debentures due September 15, 2013	400,000	-
Series 2002A, Indiana Development Finance Authority Environmental Refunding Revenue Bonds, due March 1, 2031	23,000	23,000
Series 2002B, Indiana Development Finance Authority Environmental Refunding Revenue Bonds, due March 1, 2019	24,600	24,600
Series 2003, Indiana Development Finance Authority Environmental Refunding Revenue Bonds, due April 1, 2022	35,000	–
Total Other Long-term Debt	1,032,663	598,700
Unamortized Premium and Discount — Net	(10,407)	(7,736)
Total PSI Long-term Debt	1,720,476	1,315,984
Total Consolidated Long-term Debt	$4,131,909	$4,011,568
Preferred Trust Securities		
Company obligated, mandatorily redeemable, preferred trust securities of subsidiary, holding solely debt securities of the company	$ –	$ 308,187

Cumulative Preferred Stock of Subsidiaries

	Par/Stated Value	Authorized Shares	Shares Outstanding at December 31, 2003	Series	Mandatory Redemption	2003	2002
CG&E	$100	6,000,000	204,849	4% – 4¾%	No	$ 20,485	$ 20,485
PSI	$100	5,000,000	347,445	3½% – 6⅞%	No	34,744	34,754
PSI	$ 25	5,000,000	303,544	4.16% – 4.32%	No	7,589	7,589
Total Cumulative Preferred Stock of Subsidiaries						62,818	62,828

	2003	2002
Common Stock Equity		
Common Stock — $0.01 par value; authorized shares — 600,000,000; issued shares — 178,438,369 at December 31, 2003, and 168,663,115 at December 31, 2002; outstanding shares — 178,336,854 at December 31, 2003 and 168,663,115 at December 31, 2002	$ 1,784	$ 1,687
Paid-in capital	2,195,985	1,918,136
Retained earnings	1,551,003	1,403,453
Treasury shares at cost — 101,515 shares at December 31, 2003	(3,255)	–
Accumulated other comprehensive income (loss)	(44,835)	(29,800)
Total Common Stock Equity	3,700,682	3,293,476
Total — Consolidated Capitalization	$7,895,409	$7,676,059

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

RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management is responsible for the accuracy, objectivity, and consistency of the financial statements presented in this report. The Consolidated Financial Statements of Cinergy Corp. (Cinergy) conform to generally accepted accounting principles and have also been prepared to comply with accounting policies and principles prescribed by the applicable regulatory authorities.

To assure the reliability of Cinergy's financial statements, management maintains a system of internal controls. This system is designed to provide reasonable assurance that assets are safeguarded, that transactions are executed with management's authorization, and that transactions are properly recorded so financial statements can be prepared in accordance with the policies and principles previously described.

Cinergy has established policies intended to ensure that employees adhere to the highest standards of business ethics. Management also takes steps to assure the integrity and objectivity of Cinergy's accounts by careful selection of managers, division of responsibilities, delegation of authority, and communication programs to assure that policies and standards are understood.

An internal auditing program is used to evaluate the adequacy of and compliance with internal controls. Although no cost effective internal control system will preclude all errors and irregularities, management believes that Cinergy's system of internal controls provides reasonable assurance that material errors or irregularities are prevented, or would be detected within a timely period.

Cinergy's Consolidated Financial Statements have been audited by Deloitte & Touche LLP, which has expressed its opinion with respect to the fairness of the statements. The auditors' examination included a review of the system of internal controls and tests of transactions to the extent they considered necessary to render their opinion.

The Board of Directors, through its audit committee of outside directors, meets periodically with management, internal auditors, and independent auditors to assure that they are carrying out their respective responsibilities. The audit committee has full access to the internal and independent auditors, and meets with them, with and without management present, to discuss auditing and financial reporting matters.

James E. Rogers

James E. Rogers
President and Chief Executive Officer

R. Foster Duncan

R. Foster Duncan
Executive Vice President and Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Cinergy Corp.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Cinergy Corp. and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements 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 Cinergy Corp. 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.

As discussed in Note 1 to the financial statements, in 2003 Cinergy Corp. adopted Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations;" Financial Accounting Standards Board Interpretation No. 46, "Consolidation of Variable Interest Entities;" Emerging Issues Task Force Issue 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities;" and the fair value recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation." In 2002, Cinergy Corp. adopted SFAS No. 142, "Goodwill and Other Intangible Assets."

Deloitte & Touche LLP

Deloitte & Touche LLP
Cincinnati, Ohio
February 16, 2004

In this report Cinergy (which includes Cinergy Corp. and all of our regulated and non-regulated subsidiaries) is, at times, referred to in the first person as "we", "our", or "us".

1. Summary of Significant Accounting Policies

(A) NATURE OF OPERATIONS

Cinergy Corp., a Delaware corporation organized in 1993, owns all outstanding common stock of The Cincinnati Gas & Electric Company (CG&E) and PSI Energy, Inc. (PSI), both of which are public utilities. As a result of this ownership, we are considered a utility holding company. Because we are a holding company with material utility subsidiaries operating in multiple states, we are registered with and are subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935, as amended (PUHCA). Our other principal subsidiaries are:

- Cinergy Services, Inc. (Services);
- Cinergy Investments, Inc. (Investments); and
- Cinergy Wholesale Energy, Inc. (Wholesale Energy).

CG&E, an Ohio corporation organized in 1837, is a combination electric and gas public utility company that provides service in the southwestern portion of Ohio and, through its subsidiaries, in nearby areas of Kentucky and Indiana. CG&E is responsible for the majority of our power marketing and trading activity. CG&E's principal subsidiary, The Union Light, Heat and Power Company (ULH&P), is a Kentucky corporation organized in 1901, that provides electric and gas service in northern Kentucky. CG&E's other subsidiaries are insignificant to its results of operations.

In 2001, CG&E began a transition to electric deregulation and customer choice. Currently, the competitive retail electric market in Ohio is in the development stage. CG&E is recovering its Public Utilities Commission of Ohio (PUCO) approved costs and retail electric rates are frozen during this market development period. In January 2003, CG&E filed an application with the PUCO for approval of a methodology to establish how market-based rates for non-residential customers will be determined when the market development period ends. In December 2003, the PUCO requested that CG&E propose a rate stabilization plan. In January 2004, CG&E complied with the PUCO request and filed an electric reliability and rate stabilization plan. See Note 17 for a discussion of key elements of Ohio deregulation.

PSI, an Indiana corporation organized in 1942, is a vertically integrated and regulated electric utility that provides service in north central, central, and southern Indiana.

The following table presents further information related to the operations of our domestic utility companies (our operating companies):

PRINCIPAL LINE(S) OF BUSINESS
CG&E and subsidiaries
• Generation, transmission, distribution, and sale of electricity
• Sale and/or transportation of natural gas
• Electric commodity marketing and trading operations
PSI
• Generation, transmission, distribution, and sale of electricity

Services is a service company that provides our subsidiaries with a variety of centralized administrative, management, and support services. Investments holds most of our domestic non-regulated, energy-related businesses and investments, including gas marketing and trading operations.

Wholesale Energy, through a wholly-owned subsidiary, Cinergy Power Generation Services, LLC (Generation Services), provides electric production-related construction, operation, and maintenance services to certain affiliates and non-affiliated third parties.

We conduct operations through our subsidiaries and manage our businesses through the following three reportable segments:

- Commercial Business Unit (Commercial), formerly named the Energy Merchant Business Unit;
- Regulated Businesses Business Unit (Regulated Businesses); and
- Power Technology and Infrastructure Services Business Unit (Power Technology).

For further discussion of our reportable segments see Note 15.

(B) PRESENTATION

Management makes estimates and assumptions when preparing financial statements under generally accepted accounting principles (GAAP). Actual results could differ, as these estimates and assumptions involve judgment. These estimates and assumptions affect various matters, including:

- the reported amounts of assets and liabilities in our Balance Sheets at the dates of the financial statements;
- the disclosure of contingent assets and liabilities at the dates of the financial statements; and
- the reported amounts of revenues and expenses in our Statements of Income during the reporting periods.

Additionally, we have reclassified certain prior-year amounts in our financial statements to conform to current presentation.

We use three different methods to report investments in subsidiaries or other companies: the consolidation method, the equity method, and the cost method.

(i) Consolidation Method

For traditional operating entities, we use the consolidation method when we own a majority of the voting stock of or have the ability to control a subsidiary. For variable interest entities (VIE) (discussed further in Note 3), we use the consolidation method when we anticipate absorbing a majority of the losses or returns of an entity, should they occur. We eliminate all significant intercompany transactions when we consolidate these accounts. Our consolidated financial statements include the accounts of Cinergy and its wholly-owned subsidiaries.

(ii) Equity Method

We use the equity method to report investments, joint ventures, partnerships, subsidiaries, and affiliated companies in which we do not have control, but have the ability to exercise influence over operating and financial policies (generally, 20 percent to 50 percent ownership). Under the equity method we report:

- our investment in the entity as *Investments in unconsolidated subsidiaries* in our Balance Sheets; and
- our percentage share of the earnings from the entity as *Equity in earnings (losses) of unconsolidated subsidiaries* in our Statements of Income.

(iii) Cost Method

We use the cost method to report investments, joint ventures, partnerships, subsidiaries, and affiliated companies in which we do not have control and are unable to exercise significant influence over operating and financial policies (generally, up to 20 percent ownership). Under the cost method we report our investments in the entity as *Other investments* in our Balance Sheets.

(C) REGULATION

Our operating companies and certain of our non-utility subsidiaries must comply with the rules prescribed by the SEC under the PUHCA. Our operating companies must also comply with the rules prescribed by the Federal Energy Regulatory Commission (FERC) and the applicable state utility commissions of Ohio, Indiana, and Kentucky.

Our operating companies use the same accounting policies and practices for financial reporting purposes as non-regulated companies under GAAP. However, sometimes actions by the FERC and the state utility commissions result in accounting treatment different from that used by non-regulated companies. When this occurs, we apply the provisions of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (Statement 71). In accordance with Statement 71, we record regulatory assets and liabilities (expenses deferred for future recovery from customers or amounts provided in current rates to cover costs to be incurred in the future, respectively) on our Balance Sheets.

Comprehensive electric deregulation legislation was passed in Ohio in July 1999. As required by the legislation, CG&E filed its Proposed Transition Plan for approval by the PUCO in December 1999. In August 2000, the PUCO approved a stipulation agreement relating to CG&E's transition plan. This plan created a Regulatory Transition Charge (RTC) designed to recover CG&E's generation-related regulatory assets and transition costs over a ten-year period which began January 1, 2001. Accordingly, Statement 71 was discontinued for the generation portion of CG&E's business and Statement of Financial Accounting Standards No. 101, *Regulated Enterprises — Accounting for the Discontinuation of Application of FASB Statement No. 71* was applied. The effect of this change on the financial statements was immaterial. Except with respect to the generation-related assets and liabilities of CG&E, as of December 31, 2003, our operating companies continue to meet the criteria of Statement 71. However, to the extent other states implement deregulation legislation, the application of Statement 71 will need to be reviewed. Based on our operating companies' current regulatory orders and the regulatory environment in which they currently operate, the recovery of regulatory assets recognized in the accompanying Balance Sheets as of December 31, 2003, is probable. For a further discussion of Ohio deregulation see Note 17. For a further discussion on PSI's pending retail rate case see Note 11(B)*(i)*.

Our regulatory assets, liabilities, and amounts authorized for recovery through regulatory orders at December 31, 2003, and 2002, are as follows:

	2003			2002		
(in millions)	CG&E[1]	PSI	Cinergy	CG&E[1]	PSI	Cinergy
Regulatory assets						
Amounts due from customers — income taxes[2]	$ 53	$ 22	$ 75	$ 53	$ 25	$ 78
Gasification services agreement buyout costs[3] [6]	–	235	235	–	240	240
Post-in-service carrying costs and deferred operating expenses[6] [7]	2	70	72	1	42	43
Coal contract buyout costs	–	–	–	–	10	10
Deferred merger costs	1	46	47	1	51	52
Unamortized costs of reacquiring debt	17	28	45	9	30	39
Coal gasification services expenses[6]	–	1	1	–	4	4
RTC recoverable assets[4] [6]	517	–	517	537	–	537
Other	5	15	20	4	16	20
Total Regulatory assets	$ 595	$ 417	$1,012	$605	$418	$1,023
Total Regulatory assets authorized for recovery[5]	$ 587	$ 317	$ 905	$598	$360	$ 958
Regulatory liabilities						
Accrued cost of removal[8]	$(155)	$(336)	$ (491)	$ –	$ –	$ –

(1) Includes $13 million at December 31, 2003, and $5 million at December 31, 2002, related to ULH&P's regulatory assets. Of these amounts, $11.7 million at December 31, 2003, and $3.6 million at December 31, 2002, have been authorized for recovery. Includes $(27) million of regulatory liabilities at December 31, 2003 related to ULH&P.

(2) The various regulatory commissions overseeing the regulated business operations of our operating companies regulate income tax provisions reflected in customer rates. In accordance with the provisions of Statement 71, we have recorded net regulatory assets for CG&E, PSI, and ULH&P.

(3) PSI reached an agreement with Dynegy, Inc. to purchase the remainder of its 25-year contract for coal gasification services. In accordance with an order from the Indiana Utility Regulatory Commission (IURC), PSI began recovering this asset over an 18-year period that commenced upon the termination of the gas services agreement in 2000.

(4) In August 2000, CG&E's deregulation transition plan was approved. Effective January 1, 2001, a RTC went into effect and provides for recovery of all then existing generation-related regulatory assets and various transition costs over a ten-year period. Because a separate charge provides for recovery, these assets were aggregated and are included as a single amount in this presentation. The classification of all transmission and distribution related regulatory assets has remained the same.

(5) At December 31, 2003, these amounts were being recovered through rates charged to customers over a period ranging from 1 to 49 years for CG&E, 1 to 30 years for PSI, and 1 to 17 years for ULH&P.

(6) Regulatory assets earning a return at December 31, 2003.

(7) For PSI amount includes $30 million that is not yet authorized for recovery and currently is not earning a return at December 31, 2003. See Note 11(B)(i) for information on the PSI retail electric rate case.

(8) Represents amounts received for anticipated future removal and retirement costs of regulated property, plant, and equipment. These amounts were recharacterized as regulatory liabilities upon adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (Statement 143), which prohibits the accrual of such amounts unless removal (or other retirement activity) is required pursuant to a legal obligation. See (J) and (Q)(iii) below for further discussion of Statement 143.

(D) REVENUE RECOGNITION

(i) Utility Revenues

Our operating companies record *Operating Revenues* for electric and gas service when delivered to customers. Customers are billed throughout the month as both gas and electric meters are read. We recognize revenues for retail energy sales that have not yet been billed, but where gas or electricity has been consumed. This is termed "unbilled revenue" and is a widely recognized and accepted practice for utilities. In making our estimates of unbilled revenue, we use complex systems that consider various factors, including weather, in our calculation of retail customer consumption at the end of each month. Given the use of these systems and the fact that customers are billed monthly, we believe it is unlikely that materially different results will occur in future periods when revenue is subsequently billed. The amount of unbilled revenues for Cinergy as of December 31, 2003, 2002, and 2001 were $176 million, $153 million, and $172 million, respectively.

(ii) Energy Marketing and Trading Revenues

We market and trade electricity, natural gas, coal, and other energy-related products. Many of the contracts associated with these products qualify as derivatives in accordance with Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (Statement 133), further discussed in (K)*(i)* below. We designate derivative transactions as either trading or non-trading at the time they are originated in accordance with Emerging Issues Task Force (EITF) Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3). Generally, trading contracts are reported on a net basis and non-trading contracts are reported on a gross basis.

1. Gross Reporting Gross reporting requires presentation of sales contracts in *Operating Revenues* and purchase contracts in *Fuel and purchased and exchanged power* expense or *Gas purchased* expense. Non-trading derivatives typically involve physical delivery of the underlying commodity and are therefore generally presented on a gross basis.

Derivatives are classified as non-trading only when (a) the contracts involve the purchase of gas or electricity to serve our native load requirements (end-use customers within our public utility companies' franchise service territory), or (b) the contracts involve the sale of gas or electricity and we have the intent and projected ability to fulfill substantially all obligations from company-owned assets, which generally is limited to the sale of generation to third parties when it is not required to meet native load requirements.

Energy activities that do not principally involve derivatives (e.g., natural gas sales from storage) are presented on a gross basis.

2. Net Reporting Net reporting requires presentation of realized and unrealized gains and losses on trading derivatives on a net basis in *Operating Revenues*. Prior to 2003, the realized results for trading contracts that were physical in nature were presented on a gross basis. In 2003, we began reflecting the results of trading derivatives on a net basis pursuant to the requirements of EITF 02-3, regardless of whether the transactions were settled physically. The presentation for 2002 and 2001 has been reclassified to conform to the new presentation. See (Q)*(i)* below for further discussion.

Energy derivatives involving frequent buying and selling with the objective of generating profits from differences in price are classified as trading and reported net.

(E) ENERGY PURCHASES AND FUEL COSTS

The expenses associated with electric and gas services include:

- fuel used to generate electricity;
- electricity purchased from others;
- natural gas purchased from others; and
- transportation costs associated with the purchase of fuel and natural gas.

These expenses are shown in our Statements of Income as *Fuel and purchased and exchanged power* expense and *Gas purchased* expense.

Indiana law limits the amount of fuel costs that PSI can recover to an amount that will not result in earning a return in excess of that allowed by the IURC. Due to deregulation in the state of Ohio, we no longer have direct recovery of fuel costs.

PSI utilizes a purchased power tracking mechanism (Tracker) approved by the IURC for the recovery of costs related to certain specified purchases of power necessary to meet native load peak demand requirements to the extent such costs are not recovered through the existing fuel adjustment clause. See Note 11(B)*(v)* for additional information.

(F) CASH AND CASH EQUIVALENTS

We define *Cash and cash equivalents* on our Balance Sheets and Statements of Cash Flows as investments with maturities of three months or less when acquired.

(G) INVENTORY

Prior to January 1, 2003, natural gas inventory for our gas trading operations was accounted for at fair value. All other inventory was accounted for at the lower of cost or market, cost being determined through the weighted average method. Effective January 1, 2003, accounting for our gas trading operations' gas inventory was adjusted to the lower of cost or market method with a cumulative effect adjustment, as required by EITF 02-3. See (Q)*(vi)* below for a summary of the cumulative effect adjustments.

(H) PROPERTY, PLANT, AND EQUIPMENT

Property, Plant, and Equipment includes the utility and non-regulated business property and equipment that is in use, being held for future use, or under construction. We report our *Property, Plant, and Equipment* at its original cost, which includes:

- materials;
- contractor fees;
- salaries;
- payroll taxes;
- fringe benefits;
- financing costs of funds used during construction (described below in *(ii)* and *(iii)*); and
- other miscellaneous amounts.

We capitalize costs for regulated property, plant, and equipment that are associated with the replacement or the addition of equipment that is considered a property unit. Property units are intended to describe an item or group of items. The cost of normal repairs and maintenance is expensed as incurred. On an annual basis, we perform major pre-planned maintenance activities on our generating units. These pre-planned activities are accounted for when incurred. When regulated property, plant, and equipment is retired, Cinergy charges the original cost, less salvage, to *Accumulated depreciation* and the cost of removal to *Accrued cost of removal*, which is consistent with the composite method of depreciation. A gain or loss is recorded on the sale of regulated property, plant, and equipment if an entire operating unit, as defined by the FERC, is sold. A gain or loss is recorded on non-regulated property, plant, and equipment whenever there is a related sale or retirement.

(i) Depreciation

We determine the provisions for depreciation expense using the straight-line method. The depreciation rates are based on periodic studies of the estimated useful lives and the net cost to remove the properties. Inclusion of cost of removal in depreciation rates was discontinued for all non-regulated property beginning in 2003 as a result of adopting Statement 143. See (Q)*(iii)* below for additional discussion of this change. Our operating companies use composite depreciation rates. These rates are approved by the respective state utility commissions with respect to regulated property. The average depreciation rates for *Property, Plant, and Equipment*, excluding software, for the years ended December 31, 2003, 2002, and 2001 were 2.8%, 3.0%, and 3.0%, respectively.

During the third quarter of 2003, CG&E implemented a new depreciation study of its non-regulated generating assets resulting in an increase in the estimated useful lives of certain assets. The impact of this change in accounting estimate on our net income and Earnings Per Common Share (EPS)-assuming dilution was an increase of $9 million (net of tax) or $0.05 per share, respectively. The prospective impact of this change in accounting estimate on annual net income is expected to be $18 million (net of tax).

(ii) Allowance for Funds Used During Construction (AFUDC)

Our operating companies finance construction projects with borrowed funds and equity funds. Regulatory authorities allow us to record the costs of these funds as part of the cost of construction projects. AFUDC is calculated using a methodology authorized by the regulatory authorities. These costs are credited on the Statements of Income to *Miscellaneous Income — Net* and *Interest Expense* for the equity and borrowed funds, respectively.

The equity component of AFUDC for the years ended December 31, 2003, 2002, and 2001, was $7.5 million, $12.9 million, and $8.6 million, respectively.

The borrowed funds component of AFUDC, which is recorded on a pre-tax basis, for the years ended December 31, 2003, 2002, and 2001, was $5.7 million, $10.1 million, and $8.4 million, respectively.

With the deregulation of CG&E's generation assets, the AFUDC method is no longer used to capitalize the cost of funds used during generation-related construction at CG&E. See *(iii)* below for a discussion of capitalized interest.

(iii) Capitalized Interest

Cinergy capitalizes interest costs for non-regulated construction projects in accordance with Statement of Financial Accounting Standards No. 34, *Capitalization of Interest Cost* (Statement 34). The primary differences from AFUDC are that the Statement 34 methodology does not include a component for equity funds and does not emphasize short-term borrowings over long-term borrowings. Capitalized interest costs, which are recorded on a pre-tax basis, for the years ended December 31, 2003, 2002, and 2001, were $7.7 million, $7.2 million, and $7.1 million, respectively.

(I) IMPAIRMENT OF LONG-LIVED ASSETS

We evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. So long as an asset or group of assets is not held for sale, the determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for an impairment loss if the carrying value is greater than the fair value. Once assets are classified as held for sale, the comparison of undiscounted cash flows to carrying value is disregarded and an impairment loss is recognized for any amount by which the carrying value exceeds the fair value of the assets less cost to sell.

(J) ASSET RETIREMENT OBLIGATIONS AND ACCRUED COST OF REMOVAL

We recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in property, plant, and equipment. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to property, plant, and equipment), and for accretion of the liability due to the passage of time (recognized as *Operation and maintenance* expense). Additional depreciation expense is recorded prospectively for any property, plant, and equipment increases.

We do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. CG&E and PSI have asset retirement obligations associated with river structures at certain generating stations. However, the retirement date for these river structures cannot be reasonably estimated; therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the financial statements herein.

CG&E's transmission and distribution business, PSI, and ULH&P ratably accrue the estimated retirement and removal cost of rate regulated property, plant, and equipment when removal of the asset is considered likely, in accordance with established regulatory practices. The accrued, but not incurred, balance for these costs is classified as *Accrued cost of removal* and represents a regulatory liability, under Statement 71, as disclosed in (C). Effective with our adoption of Statement 143, on January 1, 2003, we do not accrue the estimated cost of removal when no legal obligation associated with retirement or removal exists for any of our non-regulated assets (including CG&E's generation assets). See (Q)*(iii)* for additional information regarding the adoption of Statement 143 and the related impacts to *Accrued cost of removal*.

(K) DERIVATIVES

We account for derivatives under Statement 133, which requires all derivatives, subject to certain exemptions, to be accounted for at fair value. Changes in a derivative's fair value must be recognized currently in earnings unless specific hedge accounting criteria are met. Gains and losses on derivatives that qualify as hedges can (a) offset related fair value changes on the hedged item in the Statements of Income for fair value hedges; or (b) be recorded in other comprehensive income for cash flow hedges. To qualify for hedge accounting, derivatives must be designated as a hedge (for example, an offset of interest rate risks) and must be effective at reducing the risk associated with the hedged item. Accordingly, changes in the fair values or cash flows of instruments designated as hedges must be highly correlated with changes in the fair values or cash flows of the related hedged items.

(i) Energy Marketing and Trading

We account for all energy trading derivatives at fair value. These derivatives are shown in our Balance Sheets as *Energy risk management assets* and *Energy risk management liabilities*. Changes in a derivative's fair value represent unrealized gains and losses and are recognized as revenues in our Statements of Income unless specific hedge accounting criteria are met.

Non-trading derivatives involve the physical delivery of energy and are therefore typically accounted for as accrual contracts, unless the contract does not qualify for the normal purchases and sales scope exception in Statement 133.

Although we intend to settle accrual contracts with company-owned assets, occasionally we settle these contracts with purchases on the open trading markets. The cost of these purchases could be in excess of the associated revenues. We recognize the gains or losses on these transactions as delivery occurs. Open market purchases may occur for the following reasons:

- generating station outages;
- least-cost alternative;
- native load requirements; and
- extreme weather.

We value derivatives using end-of-the-period fair values, utilizing the following factors (as applicable):

- closing exchange prices (that is, closing prices for standardized electricity and natural gas products traded on an organized exchange, such as the New York Mercantile Exchange);
- broker-dealer and over-the-counter price quotations; and
- model pricing (which considers time value and historical volatility factors of electricity and natural gas).

In October 2002, the EITF reached a consensus in EITF 02-3 to rescind EITF Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities* (EITF 98-10). EITF 98-10 permitted non-derivative contracts to be accounted for at fair value if certain criteria were met. Effective with the adoption of EITF 02-3 on January 1, 2003, non-derivative contracts and natural gas inventory previously accounted for at fair value were required to be accounted for on an accrual basis, with gains and losses on the transactions being recognized at the time the contract was settled. See (Q)*(vi)* below for a summary of cumulative effect adjustments.

As a response to this discontinuance of fair value accounting, in June 2003, we began designating derivatives as fair value hedges for certain volumes of our natural gas inventory. Under this accounting election, changes in the fair value of both the derivative as well as the hedged item (the specified inventory) are included in the Statements of Income. We assess the effectiveness of the derivatives in offsetting the change in fair value of the inventory on a quarterly basis. For the year ended, December 31, 2003, the hedges' ineffectiveness was not material.

(ii) Financial

In addition to energy marketing and trading, we use derivative financial instruments to manage exposure to fluctuations in interest rates. We use interest rate swaps (an agreement by two parties to exchange fixed-interest rate cash flows for floating-interest rate cash flows) and treasury locks (an agreement that fixes the yield or price on a specific treasury security for a specific period, which we sometimes use in connection with the issuance of fixed rate debt). We account for such derivatives at fair value and assess the effectiveness of any such derivative used in hedging activities.

At December 31, 2003, the ineffectiveness of instruments that we have classified as cash flow hedges of variable-rate debt instruments was not material. Reclassification of unrealized gains or losses on cash flow hedges of debt instruments from *Accumulated other comprehensive income (loss)* occurs as interest is accrued on the debt instrument. The unrealized losses that will be reclassified as a charge to *Interest Expense* during the twelve-month period ending December 31, 2004, are not expected to be material.

(L) INTANGIBLE ASSETS

We adopted Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (Statement 142) in the first quarter of 2002. With the adoption of Statement 142, goodwill and other intangibles with indefinite lives are no longer amortized. Prior to adoption, we amortized goodwill on a straight-line basis over its estimated useful life, not to exceed 40 years. The discontinuance of this amortization was not material to our financial position or results of operations.

Statement 142 requires that goodwill is assessed annually, or when circumstances indicate that the fair value of a reporting unit has declined significantly, by applying a fair-value-based test. This test is applied at the "reporting unit" level, which is not broader than the current business segments discussed in Note 15. Acquired intangible assets are separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented, or exchanged, regardless of intent to do so.

We finalized our transition impairment test in the fourth quarter of 2002 and recognized a non-cash impairment charge of approximately $11 million (net of tax) for goodwill related to certain of our international assets. This amount is reflected in our Statements of Income as a cumulative effect adjustment, net of tax. See (Q)*(vi)* below for a summary of the cumulative effect adjustments.

(M) INCOME TAXES

We file a consolidated federal income tax return and combined/consolidated state and local tax returns in certain jurisdictions. Cinergy and its subsidiaries have an income tax allocation agreement, which conforms to the requirements of the PUHCA. The corporate taxable income method is used to allocate tax benefits to the subsidiaries whose investments or results of operations provide those tax benefits. Any tax liability not directly attributable to a specific subsidiary is allocated proportionately among the subsidiaries as required by the agreement.

Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*, requires an asset and liability approach for financial accounting and reporting of income taxes. The tax effects of differences between the financial reporting and tax basis of accounting are reported as *Deferred income tax assets or liabilities* in our Balance Sheets and are based on currently enacted income tax rates.

Investment tax credits, which have been used to reduce our federal income taxes payable, have been deferred for financial reporting purposes. These deferred investment tax credits are being amortized over the useful lives of the property to which they are related. For a further discussion of income taxes, see Note 10.

(N) ENVIRONMENTAL AND LEGAL CONTINGENCIES

In the normal course of business, we are subject to various regulatory actions, proceedings, lawsuits and other matters, including actions under laws and regulations related to the environment. We reserve for these potential contingencies when they are deemed probable and reasonably estimable liabilities. We believe that the amounts provided for in our financial statements are adequate. However, these amounts are estimates based upon assumptions involving judgment and therefore actual results could differ. For further discussion of contingencies, see Note 11.

(O) PENSION AND OTHER POSTRETIREMENT BENEFITS

We provide benefits to retirees in the form of pension and other postretirement benefits. Our reported costs of providing these pension and other postretirement benefits are developed by actuarial valuations and are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Changes made to the provisions of the plans may impact current and future pension costs. Pension costs associated with our defined benefit plans are impacted by employee demographics, the level of contributions we make to the plan, and earnings on plan assets. These pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation. Other postretirement benefit costs are impacted by employee demographics, per capita claims costs, and health care cost trend rates and may also be affected by changes in key actuarial assumptions, including the discount rate used in determining the accumulated postretirement benefit obligation. We review and update our actuarial assumptions on an annual basis, unless plan amendments or other significant events require earlier remeasurement at an interim period. For additional information on pension and other postretirement benefits, see Note 9.

(P) STOCK-BASED COMPENSATION

In 2003, we prospectively adopted accounting for our stock-based compensation plans using the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (Statement 123), as amended by Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation-Transition and Disclosure* (Statement 148), for all employee awards granted or with terms modified on or after January 1, 2003. Prior to 2003, we had accounted for our stock-based compensation plans using the intrinsic value method under Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25). See Note 2(C) for further information on our stock-based compensation plans. The following table illustrates the effect on our *Net Income* and EPS if the fair value based method had been applied to all outstanding and unvested awards in each period.

	Year Ended December 31		
(in millions, except per share amounts)	2003	2002	2001
Net income, as reported	$ 470	$ 361	$ 442
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects.	17	24	13
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects.	18	23	13
Pro-forma net income	$ 469	$ 362	$ 442
EPS — as reported	$2.66	$2.16	$2.78
EPS — pro-forma	$2.66	$2.17	$2.78
EPS assuming dilution — as reported	$2.63	$2.13	$2.75
EPS assuming dilution — pro-forma	$2.63	$2.14	$2.75

The pro-forma amounts reflect certain assumptions used in estimating fair values. As a result of this and other factors which may affect the timing and amounts of stock-based compensation, the pro-forma effect on *Net Income* and EPS may not be representative of future periods. See Note 2(C) for further description of the fair value assumptions.

(Q) ACCOUNTING CHANGES

(i) Energy Trading

In October 2002, the EITF reached consensus in EITF 02-3, to (a) rescind EITF 98-10, (b) generally preclude the recognition of gains at the inception of new derivatives, and (c) require all realized and unrealized gains and losses on energy trading derivatives to be presented net in the Statements of Income, whether or not settled physically.

The consensus to rescind EITF 98-10 required all energy trading contracts that do not qualify as derivatives to be accounted for on an accrual basis, rather than at fair value. The consensus was immediately effective for all new contracts executed after October 25, 2002, and required a cumulative effect adjustment to income, net of tax, on January 1, 2003, for all contracts executed on or prior to October 25, 2002. The cumulative effect adjustment, on a net of tax basis, was a loss of approximately $13 million, which primarily includes the impact of certain coal contracts, gas inventory, and certain gas contracts, which are accounted for at fair value. We expect this rescission to have the largest ongoing impact on our gas trading business, which uses financial contracts, physical contracts, and gas inventory to take advantage of various arbitrage opportunities. Prior to the rescission of EITF 98-10, all of these activities were accounted for at fair value. Under the revised guidance, only certain items are accounted for at fair value, which could increase inter-period volatility in reported results of operations. As a result, we began applying fair value hedge accounting in June 2003 to certain quantities of gas inventory (more fully discussed in (K)*(i)* above) and are further reviewing additional applications for hedge accounting.

The consensus to require all gains and losses on energy trading derivatives to be presented net in the Statements of Income was effective January 1, 2003, and required reclassification for all periods presented. This resulted in substantial reductions in reported *Operating Revenues, Fuel and purchased and exchanged power* expense, and *Gas purchased* expense. However, *Operating Income* and *Net Income* were not affected by this change.

(ii) Derivatives

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (Statement 149). Statement 149 primarily amends Statement 133 to incorporate implementation conclusions previously cleared by the FASB staff, to clarify the definition of a derivative and to require derivative instruments that include up-front cash payments to be classified as a financing activity in the Statements of Cash Flows. Implementation issues previously cleared by the FASB staff were effective at the time they were cleared and new guidance was effective in the third quarter of 2003. In connection with our adoption, we reviewed certain power purchase or sale contracts to determine if they met the revised normal purchases and sales scope exception criteria in Statement 149. If these criteria were not met, the contract was adjusted to fair value. The impact of adopting Statement 149 was not material to our financial position or results of operations.

In June 2003, the FASB issued final guidance on the use of broad market indices (e.g., consumer price index) in power purchases and sales contracts. This guidance clarifies that the normal purchases and sales scope exception is precluded if a contract contains a broad market index that is not clearly and closely related to the asset being sold or purchased (or a direct factor in the production of the asset sold or purchased). The guidance provides criteria that must be met for the index to be considered clearly and closely related. This guidance, which was effective in the fourth quarter of 2003, was not material to our financial position or results of operations.

(iii) Asset Retirement Obligations

In July 2001, the FASB issued Statement 143, which requires fair value recognition beginning January 1, 2003, of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred. Statement 143 prohibits the accrual of estimated retirement and removal costs unless resulting from legal obligations. Our accounting policy for such legal obligations and for accrued cost of removal for our rate regulated long-lived assets is described in (J) above.

We adopted Statement 143 on January 1, 2003, and recognized a gain of $39 million (net of tax) for the cumulative effect of this change in accounting principle. Substantially all of this adjustment reflects the reversal of previously accrued cost of removal for generating assets, which do not apply the provisions of Statement 71. *Accrued cost of removal* at adoption included $462 million of accumulated cost of removal related to our operating companies' utility plant in service assets, which represent regulatory liabilities after adoption and were not included as part of the cumulative effect adjustment. The increases in assets and liabilities from adopting Statement 143 were not material to our financial position.

Pro-forma results as if Statement 143 was applied retroactively for the years ended December 31, 2002 and 2001, are not materially different from reported results.

(iv) Consolidation of VIEs

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities* (Interpretation 46), which significantly changes the consolidation requirements for traditional special purpose entities (SPE) and certain other entities subject to its scope. This interpretation defines a VIE as (a) an entity that does not have sufficient equity to support its activities without additional financial support or (b) an entity that has equity investors that do not have voting rights or do not absorb losses or receive returns. These entities must be consolidated when certain criteria are met. The interpretation was originally to be effective as of July 1, 2003 for Cinergy; however, the FASB subsequently permitted deferral of the effective date to December 31, 2003 for traditional SPEs and to March 31, 2004 for all other entities subject to the scope of Interpretation 46. During this deferral period, the FASB clarified and amended several provisions, much of which is intended to assist in the application of Interpretation 46 to operating entities. Clarifications were not needed for most traditional SPEs and we therefore elected to implement Interpretation 46 for such entities, as discussed below, in accordance with the original implementation date of July 1, 2003. Prior period financial statements were not restated for these changes.

Interpretation 46 required us to consolidate two SPEs that have individual power sale agreements to Central Maine Power Company (CMP). Further, we were no longer permitted to consolidate a trust that was established by Cinergy Corp. in 2001 to issue approximately $316 million of combined preferred trust securities and stock purchase contracts. For further information on the accounting for these entities see Note 3.

We have concluded that our accounts receivable sale facility, as discussed in Note 3(C), will remain unconsolidated since it involves transfers of financial assets to a qualifying SPE, which is exempted from consolidation by Interpretation 46 and Statement of Financial Accounting Standards No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities* (Statement 140).

We are continuing to evaluate the impact of Interpretation 46 on several operating joint ventures, primarily involved in cogeneration and energy efficiency operations, that we currently do not consolidate. If all these entities were consolidated, their total assets of approximately $590 million (the majority of which is non-current) and total liabilities of approximately $210 million (which includes long-term debt of approximately $90 million) would be recognized on our Balance Sheets. Our current investment in these entities is approximately $200 million. We also guarantee certain performance obligations of these entities with an estimated maximum potential exposure of approximately $40 million, as disclosed in Note 11(C)*(vii)*. If any of these entities are required to be consolidated, they will be included in the March 31, 2004 consolidated financial statements.

(v) Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* (Statement 150). Statement 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. This statement was effective for financial instruments entered into or modified after May 31, 2003, and was effective on July 1, 2003, for financial instruments held prior to issuance of this statement. Statement 150 would have required Cinergy Corp.'s preferred trust securities to be reported as a liability; however, as described more fully in Note 3(B), the trust holding these securities is no longer permitted to be consolidated and the preferred trust securities are no longer reported on our Balance Sheets. However, our note payable to the trust is recorded on the Balance Sheets as *Long-term debt*. As a result, the impact of adopting Statement 150 was not material to our financial position or results of operations.

As discussed in Note 3(B), Cinergy Corp. issued forward stock sale contracts that require purchase by the holder of a certain number of Cinergy Corp. shares in February 2005 (stock contracts). The number of shares to be issued is contingent on the market price of Cinergy Corp. stock, but subject to a predetermined ceiling and floor price. In October 2003, the FASB staff released an interpretation of Statement 150 that requires an evaluation of these stock contracts to determine whether they constitute a liability, with any changes in accounting required in January 2004. This interpretation did not have any impact on our current accounting.

(vi) Cumulative Effect of Changes in Accounting Principles, Net of Tax

The following table summarizes the various cumulative effect adjustments and their related tax effects discussed previously for the rescission of EITF 98-10 and the adoption of Statement 142 and Statement 143:

	Year to Date December 31					
	2003			2002		
(in thousands)	Before-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount	Before-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Goodwill impairment (Statement 142 adoption)	$ –	$ –	$ –	$(10,899)	$ –	$(10,899)
Rescission of EITF 98-10 (EITF 02-3 adoption)	(20,163)	7,651	(12,512)	–	–	–
Asset retirement obligation (Statement 143 adoption)	64,070	(25,096)	38,974	–	–	–
	$ 43,907	$(17,445)	$ 26,462	$(10,899)	$ –	$(10,899)

(R) TRANSLATION OF FOREIGN CURRENCY

We translate the assets and liabilities of foreign subsidiaries, whose functional currency (generally, the local currency of the country in which the subsidiary is located) is not the United States (U.S.) dollar, using the appropriate exchange rate as of the end of the year. We translate income and expense items using the average exchange rate prevailing during the month the respective transaction occurs. We record translation gains and losses in *Accumulated other comprehensive income (loss)*, which is a component of common stock equity. When a foreign subsidiary is sold, the cumulative translation gain or loss as of the date of sale is removed from *Accumulated other comprehensive income (loss)* and is recognized as a component of the gain or loss on the sale of the subsidiary in our Statements of Income.

(S) RELATED PARTY TRANSACTIONS

Our operating companies engage in related party transactions. These transactions, which are eliminated upon consolidation, are generally performed at cost and in accordance with the SEC regulations under the PUHCA and the applicable state and federal commission regulations.

2. Common Stock

(A) CHANGES IN COMMON STOCK OUTSTANDING

The following table reflects information related to shares of common stock issued for stock-based plans.

	Shares Authorized for Issuance under Plan	Number of Shares Available for Future Issuance[3]	Shares Used to Grant or Settle Awards		
			2003	2002	2001
Cinergy Corp. 1996 Long-Term Incentive Compensation Plan (LTIP)	14,500,000	4,346,877	1,742,046	674,005	72,225
Cinergy Corp. Stock Option Plan (SOP)	5,000,000	1,318,500	421,611	870,867	263,070
Cinergy Corp. Employee Stock Purchase and Savings Plan	2,000,000	1,482,664	168,756	4,912	227,847
Cinergy Corp. UK Sharesave Scheme	75,000	62,637	3,364	8,878	121
Cinergy Corp. Retirement Plan for Directors	175,000[1]	–	5,602	1,768	29,135
Cinergy Corp. Directors' Equity Compensation Plan	75,000	46,771	3,824	196	1,858
Cinergy Corp. Directors' Deferred Compensation Plan	200,000	108,547	25,826	–	14,211
Cinergy Corp. 401(k) Plans	6,469,373[1]	3,890,358	1,544,900	964,615	69,500
Cinergy Corp. Direct Stock Purchase and Dividend Reinvestment Plan[2]	3,000,000[1]	689,820	679,301	657,943	649,834
Cinergy Corp. 401(k) Excess Plan	100,000[1]	–	–	–	–

(1) Plan does not contain an authorization limit. The number of shares presented reflects amounts registered with the SEC as of December 31, 2003.
(2) Shares issued prior to April 2001 were for the previous Cinergy Corp. Dividend Reinvestment and Stock Purchase Plan, which is no longer active.
(3) Shares available exclude the number of shares to be issued upon exercise of outstanding options, warrants, and rights.

We retired 519,976 shares of common stock in 2003, 422,908 shares in 2002, and 72,739 shares in 2001, mainly representing shares tendered as payment for the exercise of previously granted stock options.

In April 2001, we adopted the Cinergy Corp. Direct Stock Purchase and Dividend Reinvestment Plan, a plan designed to provide investors with a convenient method to purchase shares of Cinergy Corp. common stock and to reinvest cash dividends in the purchase of additional shares. This plan replaced the Cinergy Corp. Dividend Reinvestment and Stock Purchase Plan.

In November 2001, we chose to reinstitute the practice of issuing new Cinergy Corp. common shares to satisfy obligations under certain of our employee stock plans and the Cinergy Corp. Direct Stock Purchase and Dividend Reinvestment Plan. This replaced our previous practice of purchasing shares in the open market to fulfill certain plan obligations.

In February 2002, we sold 6.5 million shares of Cinergy Corp. common stock with net proceeds of approximately $200 million.

In January 2003, Cinergy Corp. filed a registration statement with the SEC with respect to the issuance of common stock, preferred stock, and other securities in an aggregate offering amount of $750 million. In February 2003, we sold 5.7 million shares of Cinergy Corp. common stock with net proceeds of approximately $175 million under this registration statement. The net proceeds from the transaction were used to reduce short-term debt of Cinergy Corp. and for other general corporate purposes.

Cinergy Corp. owns all of the common stock of CG&E and PSI.

(B) DIVIDEND RESTRICTIONS

Cinergy Corp.'s ability to pay dividends to holders of its common stock is principally dependent on the ability of CG&E and PSI to pay Cinergy Corp. common stock dividends. Cinergy Corp., CG&E, and PSI cannot pay dividends on their common stock if their respective preferred stock dividends or preferred trust dividends are in arrears. The amount of common stock dividends that each company can pay is also limited by certain capitalization and earnings requirements under CG&E's and PSI's credit instruments. Currently, these requirements do not impact the ability of either company to pay dividends on its common stock.

(C) STOCK-BASED COMPENSATION PLANS

We currently have the following stock-based compensation plans:

- LTIP;
- SOP;
- Employee Stock Purchase and Savings Plan;
- UK Sharesave Scheme;
- Retirement Plan for Directors;
- Directors' Equity Compensation Plan;
- Directors' Deferred Compensation Plan; and
- 401(k) Excess Plan.

The LTIP, the SOP, the Employee Stock Purchase and Savings Plan, and the 401(k) Excess Plan are discussed below. The activity in 2003, 2002, and 2001 for the remaining stock-based compensation plans was not significant.

In 2003, we prospectively adopted accounting for our stock-based compensation plans using the fair value recognition provisions of Statement 123, as amended by Statement 148, for all employee awards granted or with terms modified on or after January 1, 2003. Prior to 2003, we had accounted for our stock-based compensation plans using the intrinsic value method under APB 25. See Stock-Based Compensation in Note 1(P) for additional information on costs we recognized in 2003, 2002, and 2001, related to stock-based compensation plans, and for our pro-forma disclosure assuming compensation costs for these plans had been determined at fair value, consistent with Statement 123, as amended by Statement 148.

(i) LTIP

The LTIP was originally adopted in 1996 and was subsequently amended effective January 2002. Under this plan, certain key employees may be granted incentive and non-qualified stock options, stock appreciation rights (SARs), restricted stock, dividend equivalents, the opportunity to earn performance-based shares and certain other stock-based awards. Stock options are granted to participants with an option price equal to or greater than the fair market value on the grant date, and generally with a vesting period of either three or five years. The vesting period begins on the grant date and all options expire within 10 years from that date. The number of shares of common stock issuable under the LTIP is limited to a total of 14.5 million shares.

Historically, the performance-based shares have been paid 100 percent in the form of common stock. In order to maintain market competitiveness with respect to the form of LTIP awards and to ensure continued compliance with internal guidelines on common share dilution, the Compensation Committee of the Cinergy Corp. Board of Directors approved the future payment of performance-based share awards 50 percent in common stock and 50 percent in cash. As a result, we have reclassified the expected cash payout portion of the performance shares from *Paid-in capital* to *Current Liabilities — Other* and *Non-Current Liabilities — Other*.

Entitlement to performance-based shares is based on our total shareholder return (TSR) over designated Cycles as measured against a pre-defined peer group. Target grants of performance-based shares were made for the following Cycles:

(in thousands)

Cycle	Grant Date	Performance Period	Target Grant of Shares
VI	1/2002	2002-2004	357
VII	1/2003	2003-2005	411
VIII	1/2004	2004-2006	404

Participants may earn additional performance shares if our TSR exceeds that of the peer group. For the three-year performance period ended December 31, 2003 (Cycle V), approximately 567,000 shares (including dividend equivalent shares) were earned, based on our relative TSR.

(ii) SOP

The SOP is designed to align executive compensation with shareholder interests. Under the SOP, incentive and non-qualified stock options, SARs, and SARs in tandem with stock options may be granted to key employees, officers, and outside directors. The activity under this plan has predominantly consisted of the issuance of stock options. Options are granted with an option price equal to the fair market value of the shares on the grant date. Options generally vest over five years at a rate of 20 percent per year, beginning on the grant date, and expire 10 years from the grant date. The total number of shares of common stock issuable under the SOP may not exceed 5,000,000 shares. No incentive stock options may be granted under the plan after October 24, 2004.

(iii) Employee Stock Purchase and Savings Plan

The Employee Stock Purchase and Savings Plan allows essentially all full-time, regular employees to purchase shares of common stock pursuant to a stock option feature. Under the Employee Stock Purchase and Savings Plan, after-tax funds are withheld from a participant's compensation during a 26-month offering period and are deposited in an interest-bearing account. At the end of the offering period, participants may apply amounts deposited in the account, plus interest, toward the purchase of shares of common stock. The purchase price is equal to 95 percent of the fair market value of a share of common stock on the first date of the offering period. Any funds not applied toward the purchase of shares are returned to the participant. A participant may elect to terminate participation in the plan at any time. Participation also will terminate if the participant's employment ceases. Upon termination of participation, all funds, including interest, are returned to the participant without penalty. The sixth offering period began May 1, 2001, and ended June 30, 2003, with 168,101 shares purchased and the remaining cash distributed to the respective participants. The purchase price for all shares under this offering was $32.78. The total number of shares of common stock issuable under the Employee Stock Purchase and Savings Plan may not exceed 2,000,000.

Activity for 2003, 2002, and 2001 for the LTIP, SOP, and Employee Stock Purchase and Savings Plan is summarized as follows:

	LTIP and SOP		Employee Stock Purchase and Savings Plan	
	Shares Subject to Option	Weighted Average Exercise Price	Shares Subject to Option	Weighted Average Exercise Price
Balance at December 31, 2000	6,990,871	$26.77	280,326	$27.73
Options granted	811,700	33.90	299,793	32.78
Options exercised	(275,393)	24.39	(227,968)	27.73
Options forfeited	(79,400)	27.29	(73,826)	29.20
Balance at December 31, 2001	7,447,778	27.63	278,325	32.78
Options granted	1,241,200(2)	32.27	–	–
Options exercised	(1,308,738)	23.96	(4,912)	32.78
Options forfeited	(18,540)	31.57	(55,243)	32.78
Balance at December 31, 2002	7,361,700	29.06	218,170	32.78
Options granted	897,100(2)	34.30	–	–
Options exercised	(1,630,046)	24.89	(168,101)	32.78
Options forfeited	(59,300)	30.51	(50,069)	32.78
Balance at December 31, 2003	6,569,454	$30.79	–	$ –
Options Exercisable(1):				
At December 31, 2001	3,763,558	$27.32		
At December 31, 2002	3,744,420	$28.98		
At December 31, 2003	3,700,346	$29.52		

(1) The options under the Employee Stock Purchase and Savings Plan are generally only exercisable at the end of the offering period.
(2) Options were not granted under the SOP during 2003 or 2002.

The weighted average fair value of options granted under the combined LTIP and the SOP plans was $4.96 in 2003, $4.95 in 2002, and $5.42 in 2001. The weighted average fair value of options granted under the Employee Stock Purchase and Savings Plan was $5.85 in 2001 (no options were granted in 2003 or 2002). The fair values of options granted were estimated as of the grant date using the Black-Scholes option-pricing model and the following assumptions:

	LTIP and SOP(1)			Employee Stock Purchase and Savings Plan(2)
	2003	2002	2001	2001
Risk-free interest rate	3.02%	3.92%	4.78%	4.22%
Expected dividend yield	5.34%	5.66%	5.42%	5.26%
Expected lives	5.35 yrs.	5.42 yrs.	5.37 yrs.	2.17 yrs.
Expected volatility	26.15%	26.45%	25.01%	30.67%

(1) Options were not granted under the SOP in 2003 or 2002.
(2) Options were not granted under the Employee Stock Purchase and Savings Plan in 2003 or 2002.

Price ranges, along with certain other information, for options outstanding under the combined LTIP and SOP plans at December 31, 2003, were as follows:

	Outstanding			Exercisable	
Exercise Price Range	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number of Shares	Weighted Average Exercise Price
$22.88 — $24.38	2,134,724	$24.00	5.27 yrs.	1,830,644	$24.03
$24.63 — $33.87	1,851,164	$32.05	7.20 yrs.	611,236	$31.93
$33.88 — $38.59	2,583,566	$35.51	6.48 yrs.	1,258,466	$36.32

(iv) 401(k) Excess Plan

The 401(k) Excess Plan is a non-qualified deferred compensation plan for a select group of Cinergy management and other highly compensated employees. It is a means by which these employees can defer additional compensation provided they have already contributed the maximum amount (pursuant to the anti-discrimination rules for highly compensated employees) under the qualified 401(k) Plan. All funds deferred are held in a rabbi trust administered by an independent trustee.

Effective January 1, 2003, each Cinergy employee whose pension benefit is determined using a cash balance formula is also eligible to receive an annual deferred profit sharing contribution, calculated as a percentage of that employee's total pay. The deferred profit sharing contribution made by Cinergy is based on our performance level for the year, and is made to the 401(k) plans in the form of Cinergy Corp. common stock. Each year's contribution must remain invested in Cinergy Corp. common stock for a minimum of three years, or until an employee reaches age 50. Employees age 50 or older may transfer their benefit from Cinergy Corp. common stock into another investment option offered under our 401(k) plans. Employees vest in their benefit upon reaching three years of service, or immediately upon reaching age 65 while employed. We have recorded approximately $1.5 million of profit sharing contribution costs for the year ended December 31, 2003.

(D) 401(k) PLANS

We sponsor 401(k) employee retirement plans that cover substantially all U.S. employees. Employees can contribute up to 50 percent of pre-tax base salary (subject to Internal Revenue Service (IRS) limits) and up to 15 percent of after-tax base salary. We make matching contributions to these plans in the form of Cinergy Corp. common stock, contributing 100 percent of the first three percent of an employee's pre-tax contributions plus 50 percent of the next two percent of an employee's pre-tax contributions. Employees are immediately vested in both their contributions and our matching contributions.

Cinergy's matching contributions for the years ended December 31, 2003, 2002, and 2001 were $18 million, $19 million, and $17 million, respectively.

(E) STOCK PURCHASE CONTRACTS

In December 2001, Cinergy Corp. issued approximately $316 million notional amount of combined securities, a component of which was stock purchase contracts. These contracts obligate the holder to purchase common shares of Cinergy Corp. stock in, and/or before, February 2005. The number of shares to be issued is contingent upon the market price of Cinergy Corp. stock, but subject to predetermined ceiling and floor prices. See Note 3(B) for further discussion of these combined securities.

3. Variable Interest Entities

(A) POWER SALE SPEs

As discussed in Note 1(Q)*(iv)*, in accordance with Interpretation 46, we were required to consolidate two SPEs that have individual power sale agreements to CMP for approximately 45 megawatts (MW) of capacity, ending in 2009, and 35 MW of capacity, ending in 2016. In addition, these SPEs have individual power purchase agreements with us to supply the power. We also provide various services, including certain credit support facilities. Upon the initial consolidation of these two SPEs on July 1, 2003, approximately $239 million of notes receivable, $225 million of non-recourse debt, and miscellaneous other assets and liabilities were included on our Balance Sheets. The debt was incurred by the SPEs to finance the buyout of the existing power contracts that CMP held with the former suppliers. The cash flows from the notes receivable are designed to repay the debt. Notes 4 and 5 provide additional information regarding the debt and the notes receivable, respectively.

(B) PREFERRED TRUST SECURITIES

In December 2001, Cinergy Corp. issued approximately $316 million notional amount of combined securities consisting of (a) 6.9 percent preferred trust securities, due February 2007, and (b) stock purchase contracts obligating the holders to purchase between 9.2 and 10.8 million shares of Cinergy Corp. common stock in February 2005. A $50 preferred trust security and stock purchase contract were sold together as a single security unit (Unit). The preferred trust securities were issued through a trust whose common stock is 100 percent owned by Cinergy Corp. The stock purchase contracts were issued directly by Cinergy Corp. The trust loaned the proceeds from the issuance of the securities to Cinergy Corp. in exchange for a note payable to the trust that was eliminated in consolidation. The proceeds of $306 million, which is net of approximately $10 million of issuance costs, were used to pay down our short-term indebtedness. In February 2005, the preferred trust securities will be remarketed and the dividend rate reset, no lower than 6.9 percent, to yield $316 million in the remarketing. The holders will use the proceeds from this remarketing to fund their obligation to purchase shares of Cinergy Corp. common stock under the stock purchase contract. The holders will pay the market price for the stock at that time, subject to a ceiling of $34.40 per share and a floor of $29.15 per share. The number of shares to be issued will vary according to the stock price, subject to the total proceeds equaling $316 million.

Each Unit will receive quarterly cash payments of 9.5 percent per annum of the notional amount, which includes the preferred trust security dividend of 6.9 percent and payment of 2.6 percent, which represents principal and interest on the stock purchase contracts. Upon delivery of the shares, these stock purchase contract payments will cease. The trust's ability to pay dividends on the preferred trust securities is solely dependent on its receipt of interest payments from Cinergy Corp. on the note payable. However, Cinergy Corp. has fully and unconditionally guaranteed the preferred trust securities.

As of July 1, 2003, we no longer consolidate the trust that was established to issue the preferred trust securities. The preferred trust securities (previously recorded as *Company obligated, mandatorily redeemable, preferred trust securities of subsidiary, holding solely debt securities of the company*) are no longer included in our Balance Sheets. In addition, the note payable owed to the trust, which has a current carrying value of $319 million, is included in *Long-term debt*.

(C) SALES OF ACCOUNTS RECEIVABLE

In February 2002, our operating companies entered into an agreement to sell certain of their accounts receivable and related collections. Cinergy Corp. formed Cinergy Receivables Company, LLC (Cinergy Receivables) to purchase, on a revolving basis, nearly all of the retail accounts receivable and related collections of our operating companies. Cinergy Corp. does not consolidate Cinergy Receivables since it meets the requirements to be accounted for as a qualifying SPE. The transfers of receivables are accounted for as sales, pursuant to Statement 140.

The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from Cinergy Receivables for a portion of the purchase price (typically approximates 25 percent of the total proceeds). The note is subordinate to senior loans that Cinergy Receivables obtains from commercial paper conduits controlled by unrelated financial institutions. Cinergy Receivables provides credit enhancement related to senior loans in the form of over-collateralization of the purchased receivables. However, the over-collateralization is calculated monthly and does not extend to the entire pool of receivables held by Cinergy Receivables at any point in time. As such, these senior loans do not have recourse to all assets of Cinergy Receivables. These loans provide the cash portion of the proceeds paid to our operating companies.

This subordinated note is a retained interest (right to receive a specified portion of cash flows from the sold assets) under Statement 140 and is classified within *Notes receivable* on our Balance Sheets. In addition, our investment in Cinergy Receivables constitutes a purchased beneficial interest (purchased right to receive specified cash flows, in our case residual cash flows), which is subordinate to the retained interests held by our operating companies. The carrying values of the retained interests are determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value. The key assumptions in estimating fair value are credit losses and selection of discount rates. Because (a) the receivables generally turn in less than two months, (b) credit losses are reasonably predictable due to each company's broad customer base and lack of significant concentration, and (c) the purchased beneficial interest is subordinate to all retained interests and thus would absorb losses first, the allocated bases of the subordinated notes are not materially different than their face value. Interest accrues to our operating companies on the retained interests using the accretable yield method, which generally approximates the stated rate on the notes since the allocated basis and the face value are nearly equivalent. Cinergy Corp. records income from Cinergy Receivables in a similar manner. We record an impairment charge against the carrying value of both the retained interests and purchased beneficial interest whenever we determine that an other-than-temporary impairment has occurred (which is unlikely unless credit losses on the receivables far exceed the anticipated level).

The key assumptions used in measuring the retained interests for sales since the inception of the new agreement are as follows (all amounts are averages of the assumptions used in sales during the period):

	2003	2002
Anticipated credit loss rate	0.6%	0.6%
Discount rate on expected cash flows	4.4%	5.0%
Receivables turnover rate[1]	12.8%	12.9%

(1) Receivables at each month-end divided by annualized sales for the month.

The hypothetical effect on the fair value of the retained interests assuming both a 10 percent and 20 percent unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history.

CG&E retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables. However, Cinergy Receivables assumes the risk of collection on the purchased receivables without recourse to our operating companies in the event of a loss. While no direct recourse to our operating companies exists, these entities risk loss in the event collections are not sufficient to allow for full recovery of their retained interests. No servicing asset or liability is recorded since the servicing fee paid to CG&E approximates a market rate.

The following table shows the gross and net receivables sold, retained interests, purchased beneficial interest, sales, and cash flows during the periods ending December 31, 2003 and 2002.

(in millions)	2003	2002
Receivables sold as of period end	$ 487	$ 483
Less: Retained interests	172	135
Net receivables sold as of period end	$ 315	$ 348
Purchased beneficial interests	$14	$10
Sales during period		
Receivables sold	$3,681	$3,233
Loss recognized on sale	36	32
Cash flows during period		
Cash proceeds from sold receivables	$3,601	$3,184
Collection fees received	2	2
Return received on retained interests	16	16

A decline in the long-term senior unsecured credit ratings of our operating companies below investment grade would result in a termination of the sale program and discontinuance of future sales of receivables, and could prevent Cinergy Receivables from borrowing additional funds from commercial paper conduits.

4. Long-Term Debt

Refer to the Statements of Capitalization for detailed information for our long-term debt.

In January 2002, PSI repaid at maturity $23 million principal amount of its Medium-term Notes, Series A. The securities were not replaced by new issues of long-term debt.

In September 2002, CG&E repaid at maturity $100 million principal amount of its First Mortgage Bonds, 7¼% Series.

Also in September 2002, CG&E borrowed the proceeds from the issuance by the Ohio Air Quality Development Authority of $84 million principal amount of its State of Ohio Air Quality Development Revenue Refunding Bonds 2002 Series A, due September 1, 2037. The issuance consists of two $42 million tranches, with the interest rate on one tranche being reset every 35 days by auction and the interest rate on the other tranche being reset every 7 days by auction. The initial interest rates for the 35-day and 7-day tranches were 1.40 percent and 1.35 percent, respectively. Proceeds from the borrowing were used in October 2002 to redeem, at par, two $42 million Series 1985 A&B Air Quality Development Authority State of Ohio Customized Purchase Revenue Bonds, due December 1, 2015. The redeemed bonds had been classified in *Notes payable and other short-term obligations*.

Additionally in September 2002, PSI borrowed the proceeds from the issuance by the Indiana Development Finance Authority of $23 million principal amount of its Environmental Refunding Revenue Bonds Series 2002A, due March 1, 2031. The initial interest rate for the bonds was 1.40 percent and resets every 35 days by auction. Proceeds from the borrowing were used in October 2002 to redeem, at par, the $23 million principal amount of Indiana Development Finance Authority Environmental Refunding Revenue Bonds Series 1998, due August 1, 2028. The redeemed bonds had been classified in *Notes payable and other short-term obligations*.

Later in September 2002, PSI borrowed the proceeds from the issuance by the Indiana Development Finance Authority of $24.6 million principal amount of its Environmental Refunding Revenue Bonds Series 2002B, due March 1, 2019. The initial interest rate for the bonds was 1.35 percent and resets every 7 days by auction. Proceeds from the issuance were used in October 2002 to redeem, at par, the $24.6 million principal amount of City of Princeton, Indiana Pollution Control Revenue Refunding Bonds 1996 Series, due March 1, 2019. The redeemed bonds had been classified in *Notes payable and other short-term obligations*.

The holders of the Ohio Air Quality Development Authority and Indiana Development Finance Authority bonds mentioned above have the benefit of a financial guaranty insurance policy that insures the payment of principal of, and interest on, the bonds when due. CG&E and PSI have each entered into an insurance agreement with the bond insurer and have pledged first mortgage bonds to secure their respective reimbursement obligations under such agreements.

Finally in September 2002, CG&E issued $500 million principal amount of its 5.70% Debentures due September 15, 2012. Proceeds from the offering were used to repay short-term indebtedness incurred in connection with general corporate purposes including capital expenditures related to environmental compliance construction, and the repayment at maturity of $100 million principal amount of CG&E's First Mortgage Bonds, 7¼% Series. In July 2002, CG&E executed a treasury lock with a notional amount of $250 million, which was designated as a cash flow hedge of 50 percent of the forecasted interest payments on this debt offering. With the issuance of the debt, the treasury lock was settled. See Note 8(A) for additional information on this treasury lock.

In October 2002, PSI filed a petition with the IURC for the purpose of securing authorization and approval to issue two subordinated promissory notes to Cinergy Corp. for the acquisition of the Butler County, Ohio and Henry County, Indiana peaking plants. In January 2003, the IURC granted this request, and in February 2003, PSI issued the notes. One subordinated note was for the principal amount of $200 million with an annual interest rate of 6.30 percent scheduled to mature on April 15, 2004. The second subordinated note was for $176 million with an annual interest rate of 6.40 percent scheduled to mature on September 1, 2004.

In March 2003, PSI borrowed the proceeds from the issuance by the Indiana Development Finance Authority of $35 million of its Environmental Refunding Revenue Bonds Series 2003, due April 1, 2022. Interest was initially set at 1.05 percent and resets every 35 days by auction. The bonds are not putable by the holders; therefore, PSI's debt obligation is classified as *Long-term debt*. Later in March 2003, the proceeds from this borrowing plus the interest income earned were used to cause the refunding of the $35 million principal amount outstanding of the City of Princeton, Indiana Pollution Control Revenue Refunding Bonds, 1997 Series. Similar to the Indiana Development Finance Authority bonds discussed above, PSI has entered into an insurance agreement with the bond insurer and has pledged first mortgage bonds to secure its reimbursement obligations under the agreement.

In April 2003, PSI redeemed $26.8 million of the following Series A, Medium-term Notes:

(in millions)

Principal Amount	Interest Rate	Maturity Date
$ 2.0	8.37%	11/08/2006
5.0	8.81	05/16/2022
3.0	8.80	05/18/2022
16.8	8.67	06/01/2022

In June 2003, CG&E issued $200 million principal amount of its 5 3/8% 2003 Series B Debentures due June 15, 2033 (effective interest rate of 5.66 percent). Proceeds from this issuance were used for general corporate purposes, including the funding of capital expenditures related to construction projects and environmental compliance initiatives, and the repayment of outstanding indebtedness.

Also, in June 2003, CG&E modified existing debt resulting in a $200 million principal amount 5.40% 2003 Series A Debenture with a 30 year maturity. The effective interest rate is 6.90 percent.

In June 2003, CG&E also redeemed its $100 million 8.28% Junior Subordinated Debentures due July 1, 2025.

We adopted Interpretation 46 on July 1, 2003, as discussed in Note 1(Q)*(iv)*. The adoption of this new accounting principle had the following effects on long-term debt:

- We no longer consolidate the trust that held *Company obligated, mandatorily redeemable, preferred trust securities of subsidiary, holding solely debt securities of the company*. This resulted in the removal of these securities from our 2003 Balance Sheet and the addition to long-term debt of a $319 million (net of discount) note payable that Cinergy Corp. owes to the trust.

- We consolidated two SPEs effective July 1, 2003. As a result, we have approximately $217 million of additional non-recourse debt as of December 31, 2003, comprised of two separate notes.

  The first note, with a December 31, 2003 balance of $110 million bears an interest rate of 7.81 percent and matures in June 2009. The second note, with a December 31, 2003 balance of $107 million, bears an interest rate of 9.23 percent and matures in November 2016.

In September 2003, PSI redeemed $56 million of its 5.93% Series B, Medium-term Notes at maturity.

In September 2003, PSI issued $400 million principal amount of its 5.00% Debentures due September 15, 2013 (effective interest rate of 5.20 percent). Proceeds from this issuance were used for the early redemption at par of two subordinated promissory notes to Cinergy Corp., as discussed above, totaling $376 million. The remaining proceeds were used to reduce short-term indebtedness associated with general corporate purposes including funding capital expenditures related to construction projects and environmental compliance initiatives.

In October 2003, CG&E redeemed its $265.5 million First Mortgage Bonds, 7.20% due October 1, 2023.

In December 2003, ULH&P redeemed $20 million of its 6.11% Senior Debentures at maturity.

In February 2004, CG&E redeemed $110 million of its 6.45% First Mortgage Bonds at maturity.

The following table reflects the long-term debt maturities excluding any redemptions due to the exercise of call provisions or capital lease obligations. Callable means the issuer has the right to buy back a given security from the holder at a specified price before maturity. Putable means the holder has the right to sell a given security back to the issuer at a specified price before maturity.

(in millions)	Long-term Debt Maturities
2004	$ 835
2005[1]	222
2006	354
2007	727
2008	550
Thereafter	2,333
Total	$5,021

(1) Includes long-term debt with put provisions of $150 million and $50 million in 2005.

Maintenance and replacement fund provisions contained in PSI's first mortgage bond indenture require: (1) cash payments, (2) bond retirements, or (3) pledges of unfunded property additions each year based on an amount related to PSI's net revenues.

In August 2000, the generation assets of CG&E were released from the first mortgage indenture lien. CG&E's remaining assets, consisting primarily of transmission and distribution assets, of approximately $2.6 billion are subject to the lien of its first mortgage bond indenture. The utility property of PSI is also subject to the lien of its first mortgage bond indenture.

5. Notes Receivable

As discussed in Note 1(O)*(iv)*, we consolidated two previously unconsolidated SPEs effective July 1, 2003. As a result, we have approximately $231 million of additional notes receivable as of December 31, 2003, comprised of two separate notes.

The first note, with a December 31, 2003 balance of $118 million, bears an effective interest rate of 7.81 percent and matures in August 2009. The second note, with a December 31, 2003 balance of $113 million, bears an effective interest rate of 9.23 percent and matures in December 2016.

The following table reflects the maturities of these notes.

(in millions)	Notes Receivable Maturities
2004	$ 17
2005	20
2006	23
2007	25
2008	29
Thereafter	117
Total	$231

6. Notes Payable and Other Short-term Obligations

Short-term obligations may include:

- short-term notes;
- commercial paper; and
- variable rate pollution control notes.

SHORT-TERM NOTES

Short-term borrowings mature within one year from the date of issuance. We primarily use unsecured revolving lines of credit and the sale of commercial paper for short-term borrowings. A portion of Cinergy Corp.'s revolving lines is used to provide credit support for commercial paper and letters of credit. When revolving lines are reserved for commercial paper or backing letters of credit, they are not available for additional borrowings. The fees paid to secure short-term borrowings were immaterial during each of the years ended December 31, 2003, 2002, and 2001.

At December 31, 2003, Cinergy Corp. had $841 million remaining unused and available capacity relating to its $1 billion revolving credit facilities. These revolving credit facilities include the following:

(in millions)

Credit Facility	Expiration	Established Lines	Outstanding and Committed	Unused and Available
364-day senior revolving(1)	April 2004			
Direct borrowing		$	$ –	$
Commercial paper support			146	
Total 364-day facility		600	146	454
Three-year senior revolving(1)	May 2004			
Direct borrowing			–	
Commercial paper support			–	
Letter of credit support			13	
Total Three-year facility		400	13	387
Total Credit Facilities		$1,000	$159	$841

(1) Cinergy Corp. has historically followed the practice of renewing its credit facilities upon expiration.

In April 2003, Cinergy Corp. successfully placed a $600 million, 364-day senior unsecured revolving credit facility. This facility replaced the $600 million, 364-day facility that expired April 30, 2003.

In addition to revolving credit facilities, Cinergy Corp., CG&E, and PSI also maintain uncommitted lines of credit. These facilities are not guaranteed sources of capital and represent an informal agreement to lend money, subject to availability, with pricing to be determined at the time of advance. Cinergy Corp., CG&E, and PSI have established uncommitted lines of $40 million, $15 million, and $60 million, respectively, all of which remained unused as of December 31, 2003.

COMMERCIAL PAPER

Cinergy Corp.'s $800 million commercial paper program is supported by Cinergy Corp.'s $1 billion revolving credit facilities. The commercial paper program at the Cinergy Corp. level supports, in part, the short-term borrowing needs of CG&E and PSI and eliminates their need for separate commercial paper programs. As of December 31, 2003, Cinergy Corp. had $146 million in commercial paper outstanding.

VARIABLE RATE POLLUTION CONTROL NOTES

We have issued certain variable rate pollution control notes (tax-exempt notes obtained to finance equipment or land development for pollution control purposes). Because the holders of these notes have the right to have their notes redeemed on a daily, weekly, or monthly basis, they are reflected in *Notes payable and other short-term obligations* on our Balance Sheets. At December 31, 2003, our operating companies had $193 million outstanding in variable rate pollution control notes, classified as short-term debt. Any short-term pollution control note borrowings outstanding do not reduce the unused and available short-term debt regulatory authority of our operating companies.

In August 2003, CG&E caused the remarketing by the Ohio Air Quality Development Authority of $84 million of its State of Ohio Air Quality Development Revenue Refunding Bonds, due September 1, 2030. The issuance consists of a $42 million 1995 Series A and a $42 million 1995 Series B. The remarketing effected the conversion from a daily interest rate reset mode supported by a letter of credit to an unsecured weekly interest rate mode. The interest rate for both series was initially set at 1.30 percent and will reset every seven days going forward. Because the holders of these notes have the right to have their notes redeemed on a weekly basis, they are reflected in *Notes payable and other short-term obligations* on our Balance Sheets.

Also in August 2003, CG&E caused the remarketing by the Ohio Air Quality Development Authority of $12.1 million of its State of Ohio Air Quality Development Revenue Bonds 2001 Series A due August 1, 2033. The remarketing effected the conversion from an unsecured one-year interest rate reset mode to a daily interest rate reset mode supported by a letter of credit. The interest rate was initially set at 0.95 percent and will be reset daily going forward. Because the holders of these notes have the right to have their notes redeemed on a daily basis, they are reflected in *Notes payable and other short-term obligations* on our Balance Sheets.

In December 2003, PSI borrowed the proceeds from the issuance by the Indiana Development Finance Authority of $80.5 million of its Indiana Development Finance Authority Environmental Revenue Bonds due December 1, 2038. The issuance consists of two $40.25 million tranches designated Series 2003A and Series 2003B. The initial interest rate for both tranches was 1.27 percent and is reset weekly. Proceeds from the borrowing will be used for the acquisition and construction of various solid waste disposal facilities located at various generating stations in Indiana. The $80.5 million is being held in escrow by an independent trustee and will be drawn down as the facilities are built. Because the holders of these notes have the right to have their notes redeemed on a weekly basis, they are reflected in *Notes payable and other short-term obligations* on our Balance Sheets.

The following table summarizes our *Notes payable and other short-term obligations*.

(in millions)	December 31, 2003			December 31, 2002		
	Established Lines	Outstanding	Weighted Average Rate	Established Lines	Outstanding	Weighted Average Rate
Cinergy Corp.						
Revolving lines	$1,000	$ –	–%	$1,000	$ 25	2.02%
Uncommitted lines(1)	40	–	–	65	–	–
Commercial paper(2)		146	1.18		473	1.81
Operating companies						
Uncommitted lines(1)	75	–	–	75	–	–
Pollution control notes		193	1.37		147	1.82
Non-regulated subsidiaries						
Revolving lines	19	10	5.90	7	1	3.28
Short-term debt		2	4.80	22	22	2.93
Total		$351	1.45%		$668	1.86%

(1) Outstanding amounts may be greater than established lines as uncommitted lenders are, at times, willing to loan funds in excess of the established lines.
(2) The commercial paper program is limited to $800 million and is supported by Cinergy Corp.'s revolving lines of credit.

In our credit facilities, Cinergy Corp. has covenanted to maintain:

- a consolidated net worth of $2 billion; and
- a ratio of consolidated indebtedness to consolidated total capitalization not in excess of 65 percent.

A breach of these covenants could result in the termination of the credit facilities and the acceleration of the related indebtedness. In addition to breaches of covenants, certain other events that could result in the termination of available credit and acceleration of the related indebtedness include:

- bankruptcy;
- defaults in the payment of other indebtedness; and
- judgments against the company that are not paid or insured.

The latter two events, however, are subject to dollar-based materiality thresholds.

As discussed in Note 1(Q)*(iv)*, long-term debt increased in 2003 resulting from the adoption of Interpretation 46. The debt which was recorded as a result of this new accounting pronouncement did not cause Cinergy Corp. to be in breach of any covenants.

7. Leases

(A) OPERATING LEASES

We have entered into operating lease agreements for various facilities and properties such as computer, communication and transportation equipment, and office space. Total rental payments on operating leases for each of the past three years are detailed in the table below. This table also shows future minimum lease payments required for operating leases with remaining non-cancelable lease terms in excess of one year as of December 31, 2003:

(in millions)	
Lease Expense	
2001	$ 61
2002	$ 64
2003	$ 72
Estimated Minimum Lease Payments	
2004	$ 41
2005	33
2006	26
2007	21
2008	13
After 2008	37
Total	$171

(B) CAPITAL LEASES

In each of the years 1999 through 2003, our operating companies entered into capital lease agreements to fund the purchase of gas and electric meters. The lease terms are for 120 months commencing with the date of purchase and contain various buyout options ranging from 48 to 105 months. It is our objective to own the meters indefinitely and the operating companies plan to exercise the buyout option at month 105. As of December 31, 2003, our effective interest rate on capital lease obligations outstanding was 5.2 percent. The meters are depreciated at the same rate as if owned by the operating companies. Our operating companies each recorded a capital lease obligation, included in *Non-Current Liabilities-Other*.

The total minimum lease payments and the present values for these capital lease items are shown below:

(in millions)	
Total minimum lease payments[1]	$68
Less: amount representing interest	(13)
Present value of minimum lease payments	$55

(1) Annual minimum lease payments are immaterial.

8. Financial Instruments

(A) FINANCIAL DERIVATIVES

We have entered into financial derivative contracts for the purpose of managing financial instrument risk.

Our current policy of managing exposure to fluctuations in interest rates is to maintain approximately 30 percent of the total amount of outstanding debt in floating interest rate debt instruments. In maintaining this level of exposure, we use interest rate swaps. Under the swaps, we agree with other parties to exchange, at specified intervals, the difference between fixed-rate and floating-rate interest amounts calculated on an agreed notional amount. CG&E has an outstanding interest rate swap agreement that decreased the percentage of floating-rate debt. Under the provisions of the swap, which has a notional amount of $100 million, CG&E pays a fixed-rate and receives a floating-rate through October 2007. This swap qualifies as a cash flow hedge under the provisions of Statement 133. As the terms of the swap agreement mirror the terms of the debt agreement that it is hedging, we anticipate that this swap will continue to be effective as a hedge. Changes in fair value of this swap are recorded in *Accumulated other comprehensive income (loss)*. Cinergy Corp. has three outstanding interest rate swaps with a combined notional amount of $250 million. Under the provisions of the swaps, Cinergy Corp. receives fixed-rate interest payments and pays floating-rate interest payments through September 2004. These swaps qualify as fair value hedges under the provisions of Statement 133. We anticipate that these swaps will continue to be effective as hedges.

Treasury locks are agreements that fix the yield or price on a specified treasury security for a specified period, which we sometimes use in connection with the issuance of fixed-rate debt. On September 23, 2002, CG&E issued $500 million principal amount senior unsecured debentures due September 15, 2012, with an interest rate of 5.70 percent. In July 2002, CG&E executed a treasury lock with a notional amount of $250 million, which was designated as a cash flow hedge of 50 percent of the forecasted interest payments on this debt offering. The treasury lock effectively fixed the benchmark interest rate (i.e., the treasury component of the interest rate, but not the credit spread) for 50 percent of the offering from July 2002 through the issuance date in order to reduce the exposure associated with treasury rate volatility. With the issuance of the debt, the treasury lock was settled. Given the use of hedge accounting, this settlement was reflected in other comprehensive income (loss) on an after-tax basis in the amount of $13 million, rather than a charge to net income. This amount will be reclassified to *Interest Expense* over the 10-year life of the related debt as interest is accrued.

See Note 1(K) for additional information on financial derivatives. In the future, we will continually monitor market conditions to evaluate whether to modify our use of financial instruments to manage risk.

(B) FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The estimated fair values of other financial instruments were as follows (this information does not claim to be a valuation of the companies as a whole):

(in millions)

	December 31, 2003		December 31, 2002	
Financial Instruments	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
First mortgage bonds and other long-term debt[1]	$4,971	$5,297	$4,188	$4,399

(1) Includes amounts reflected as Long-term debt due within one year.

The following methods and assumptions were used to estimate the fair values of each major class of instruments:

(i) Cash and cash equivalents, Restricted deposits, and Notes payable and other short-term obligations

Due to the short period to maturity, the carrying amounts reflected on the Balance Sheets approximate fair values.

(ii) Long-term debt

The fair values of long-term debt issues were estimated based on the latest quoted market prices or, if not listed on the New York Stock Exchange, on the present value of future cash flows. The discount rates used approximate the incremental borrowing costs for similar instruments.

(C) CONCENTRATIONS OF CREDIT RISK

Credit risk is the exposure to economic loss that would occur as a result of nonperformance by counterparties, pursuant to the terms of their contractual obligations. Specific components of credit risk include counterparty default risk, collateral risk, concentration risk, and settlement risk.

(i) Trade Receivables and Physical Power Portfolio

Our concentration of credit risk with respect to trade accounts receivable from electric and gas retail customers is limited. The large number of customers and diversified customer base of residential, commercial, and industrial customers significantly reduces our credit risk. Contracts within the physical portfolio of power marketing and trading operations are primarily with traditional electric cooperatives and municipalities and other investor-owned utilities. At December 31, 2003, we believe the likelihood of significant losses associated with credit risk in our trade accounts receivable or physical power portfolio is remote.

(ii) Energy Trading Credit Risk

Our extension of credit for energy marketing and trading is governed by a Corporate Credit Policy. Written guidelines document the management approval levels for credit limits, evaluation of creditworthiness, and credit risk mitigation procedures. Exposures to credit risks are monitored daily by the Corporate Credit Risk function, which is independent of all trading operations. As of December 31, 2003, approximately 97 percent of the credit exposure, net of credit collateral, related to energy trading and marketing activity was with counterparties rated Investment Grade or the counterparties' obligations were guaranteed or secured by an Investment Grade entity. No single non-investment grade counterparty accounts for more than one percent of our total credit exposure. Energy commodity prices can be extremely volatile and the market can, at times, lack liquidity. Because of these issues, credit risk is generally greater than with other commodity trading.

In December 2001, Enron Corp. (Enron) filed for protection under Chapter 11 of the U.S. Bankruptcy Code in the Southern District of New York. We decreased our trading activities with Enron in the months prior to its bankruptcy filing and filed a motion with the bankruptcy court overseeing the Enron bankruptcy seeking appropriate netting of the various payables and receivables between and among Enron and Cinergy entities. We entered into a settlement agreement with Enron, which became final in January 2004. See Note 11(C)*(iii)* for further information.

We continually review and monitor our credit exposure to all counterparties and secondary counterparties. If appropriate, we may adjust our credit reserves to attempt to compensate for increased credit risk within the industry. Counterparty credit limits may be adjusted on a daily basis in response to changes in a counterparty's financial status or public debt ratings.

(iii) Financial Derivatives

Potential exposure to credit risk also exists from our use of financial derivatives such as interest rate swaps and treasury locks. Because these financial instruments are transacted with highly rated financial institutions, we do not anticipate nonperformance by any of the counterparties.

9. Pension and Other Postretirement Benefits

We provide benefits to retirees in the form of pension and other postretirement benefits.

Our qualified defined benefit pension plans cover substantially all U.S. employees meeting certain minimum age and service requirements. During 2002, eligible Cinergy employees were offered the opportunity to make a one-time election, effective January 1, 2003, to either continue to have their pension benefit determined by the traditional defined benefit pension formula or to have their benefit determined using a cash balance formula.

The traditional defined benefit program utilizes a final average pay formula to determine pension benefits. These benefits are based on:

- years of participation;
- age at retirement; and
- the applicable average Social Security wage base or benefit amount.

Benefits are accrued under the cash balance formula based upon a percentage of pay plus interest. In addition, participants with the cash balance formula may request a lump-sum cash payment upon termination of their employment, which may result in increased cash requirements from pension plan assets. Benefits earned under the traditional defined benefit pension formula ceased accruing at December 31, 2002 only for those employees who elected the cash balance formula. There was no change to retirement benefits earned through December 31, 2002 in converting to the cash balance formula. The pension benefits of all non-union and certain union employees hired after December 31, 2002 are calculated using the cash balance formula.

The introduction of the defined benefit plan with cash balance features did not have a material effect on our financial position or results of operations for 2003.

Funding for the qualified defined benefit pension plans is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended. The pension plans' assets consist of investments in equity and debt securities.

Our investment strategy with respect to pension assets is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective, which is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The portfolio's target asset allocation is 60 percent equity and 40 percent debt with specified allowable ranges around these targets. Within the equity segment, we are broadly diversified across domestic, developed international, and emerging market equities, with the largest concentration being domestic. Further diversification is achieved through allocations to growth/value and small-, mid-, and large-cap equities. Within the debt segment, we principally maintain separate "core plus" and "core" portfolios. The "core plus" portfolio makes tactical use of the "plus" sectors (e.g., high yield, developed international, emerging markets, etc.) while the "core" portfolio is a domestic, investment grade portfolio. The use of derivatives is currently limited to collateralized mortgage obligations and asset-backed securities. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Our qualified pension plan asset allocation at September 30, 2003 and 2002 by asset category was as follows:

	Percentage of Fair Value of Plan Assets at September 30	
Asset Category	2003	2002
Equity securities(1)	62%	50%
Debt securities(2)	38%	50%

(1) The portfolio's target asset allocation is 60 percent equity with an allowable range of 50 percent to 70 percent.

(2) The portfolio's target asset allocation is 40 percent debt with an allowable range of 30 percent to 50 percent.

In addition, we sponsor non-qualified pension plans (plans that do not meet the criteria for tax benefits) that cover officers, certain other key employees, and non-employee directors. We began funding certain of these non-qualified plans through a rabbi trust in 1999. This trust, which consists of equity (63 percent) and debt (37 percent) securities at December 31, 2003, is not restricted to the payment of plan benefits and therefore, not considered plan assets under Statement of Financial Accounting Standards No. 87, *Employers' Accounting for Pensions*. At December 31, 2003 and 2002, trust assets were approximately $9 million and $8 million, respectively, and are reflected in our Balance Sheets as *Other investments*.

In 2003 and 2002, we offered voluntary early retirement programs to certain individuals. In accordance with Statement of Financial Accounting Standards No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits* (Statement 88), we recognized an expense of $8.5 million and $39.1 million in 2003 and 2002, respectively.

We provide certain health care and life insurance benefits to retired U.S. employees and their eligible dependents. These benefits are subject to minimum age and service requirements. The health care benefits include medical coverage, dental coverage, and prescription drugs and are subject to certain limitations, such as deductibles and co-payments. Neither CG&E nor ULH&P pre-fund their obligations for these postretirement benefits. In 1999, PSI began pre-funding its obligations through a grantor trust as authorized by the IURC. This trust, which consists of equity (63 percent) and debt (37 percent) securities at December 31, 2003, is not restricted to the payment of plan benefits and therefore, not considered plan assets under Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (Statement 106). At December 31, 2003 and 2002, trust assets were approximately $64 million and $52 million, respectively, and are reflected in our Balance Sheets as *Other investments*.

Based on preliminary estimates, we expect 2004 contributions of $107 million for qualified pension benefits. In addition, we expect to make contributions of $8 million and $27 million in 2004 for non-qualified pension benefits and other postretirement benefits, respectively.

Our benefit plans' costs for the past three years included the following components:

	Qualified Pension Benefits			Non-Qualified Pension Benefits			Other Postretirement Benefits		
(in millions)	2003	2002	2001	2003	2002	2001	2003	2002	2001
Service cost	$ 31.3	$ 27.3	$ 27.9	$ 3.3	$ 2.7	$2.1	$ 4.1	$ 3.5	$ 3.8
Interest cost	85.9	79.2	77.5	6.4	5.1	4.8	22.4	19.6	17.9
Expected return on plans' assets	(80.8)	(86.3)	(81.9)	–	–	–	–	(0.3)	–
Amortization of transition (asset) obligation	(1.0)	(1.3)	(1.3)	–	0.1	0.1	3.3	5.0	5.0
Amortization of prior service cost	4.8	6.2	4.6	1.3	0.9	1.1	–	–	–
Recognized actuarial (gain) loss	–	(5.4)	(3.2)	2.1	0.8	0.6	5.2	1.1	0.1
Voluntary early retirement costs (Statement 88)	8.5	38.6	–	–	0.5	–	–	–	–
Net periodic benefit cost	$ 48.7	$ 58.3	$ 23.6	$13.1	$10.1	$8.7	$35.0	$28.9	$26.8

The following table provides a reconciliation of the changes in the plans' benefit obligations and fair value of assets for 2003 and 2002, and a statement of the funded status for both years. We use a September 30 measurement date for our defined benefit pension plans and other postretirement benefit plans.

	Qualified Pension Benefits		Non-Qualified Pension Benefits		Other Postretirement Benefits	
(in millions)	2003	2002	2003	2002	2003	2002
Change in benefit obligation						
Benefit obligation at beginning of period	$1,314.9	$1,083.5	$97.8	$70.9	$343.2	$270.4
Service cost	31.3	27.3	3.3	2.7	4.1	3.5
Interest cost	85.9	79.2	6.4	5.1	22.4	19.6
Amendments(1)	0.3	43.3	0.1	4.5	(3.3)	(12.3)
Actuarial loss	97.9	156.5	7.4	20.6	54.3	80.2
Benefits paid	(72.5)	(74.9)	(7.4)	(6.0)	(22.0)	(18.2)
Benefit obligation at end of period	1,457.8	1,314.9	107.6	97.8	398.7	343.2
Change in plan assets						
Fair value of plan assets at beginning of period	756.5	875.4	–	–	–	–
Actual return on plan assets	119.3	(48.0)	–	–	–	–
Employer contribution	74.0	4.0	7.4	6.0	22.0	18.2
Benefits paid	(72.5)	(74.9)	(7.4)	(6.0)	(22.0)	(18.2)
Fair value of plan assets at end of period	877.3	756.5	–	–	–	–
Funded status	(580.5)	(558.4)	(107.6)	(97.8)	(398.7)	(343.2)
Unrecognized prior service cost	35.4	48.4	12.3	13.5	–	–
Unrecognized net actuarial loss	255.5	196.2	43.1	37.6	175.7	125.5
Unrecognized net transition (asset) obligation	(0.8)	(1.9)	–	0.1	26.9	33.5
Benefit cost at December 31	$(290.4)	$(315.7)	$(52.2)	$(46.6)	$(196.1)	$(184.2)
Amounts recognized in balance sheets						
Accrued benefit liability	$(366.2)	$(353.0)	$(100.5)	$(89.0)	$(196.1)	$(184.2)
Intangible asset	22.1	32.6	12.3	13.6	–	–
Accumulated other comprehensive income (pre-tax)	53.7	4.7	36.0	28.8	–	–
Net recognized at end of period	$(290.4)	$(315.7)	$(52.2)	$(46.6)	$(196.1)	$(184.2)

(1) For 2003, the amount of $0.3 million includes $8.5 million of voluntary early retirement expenses in accordance with Statement 88, as previously discussed. For 2002, the amounts of $43.3 million and $4.5 million include $38.6 million and $0.5 million, respectively, of voluntary early retirement expenses in accordance with Statement 88, as previously discussed.

The accumulated benefit obligation for the qualified defined benefit pension plans was $1,237.3 million and $1,101.7 million for 2003 and 2002, respectively. The accumulated benefit obligation for the non-qualified defined benefit pension plans was $102.1 million and $90.4 million for 2003 and 2002, respectively.

The weighted-average assumptions used to determine benefit obligations were as follows:

	Qualified Pension Benefits		Non-Qualified Pension Benefits		Other Postretirement Benefits	
(in millions)	2003	2002	2003	2002	2003	2002
Discount rate	6.25%	6.75%	6.25%	6.75%	6.25%	6.75%
Rate of future compensation increase	4.00	4.00	4.00	4.00	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Qualified Pension Benefits			Non-Qualified Pension Benefits			Other Postretirement Benefits		
(in millions)	2003	2002	2001	2003	2002	2001	2003	2002	2001
Discount rate	6.75%	7.50%	7.50%	6.75%	7.50%	7.50%	6.75%	7.50%	7.50%
Expected return on plans' assets	9.00	9.25	9.00	N/A	N/A	N/A	N/A	3.00	N/A
Rate of future compensation increase	4.00	4.00	4.50	4.00	4.00	4.50	N/A	N/A	N/A

Our expected long-term rate of return on plan assets is based on a calculation provided by an independent investment-consulting firm. The calculation of the expected return is a two-step process. Capital market assumptions (e.g., forecasts) are first developed for various asset classes based on underlying fundamental and economic drivers of performance. Such drivers for equity and debt instruments include profit margins, dividend yields, and interest paid for use of capital. Risk premiums for each asset class are then developed based on factors such as expected illiquidity, credit spreads, inflation uncertainty and country/currency risk. Current valuation factors such as present interest and inflation rate levels underpin this process.

The assumptions are then modeled via a probability based multi-factor capital market methodology. Through this modeling process, a range of possible 10-year annualized returns are generated for each strategic asset class. Those returns falling at the 50th percentile are utilized in the calculation of our expected long-term rate of return. We periodically request a new calculation for use in validating our current expected long-term rate of return.

The assumed health care cost trend rates were as follows:

	2003	2002
Health care cost trend rate assumed for next year	9.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2008	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 4.1	$ (3.5)
Effect on accumulated postretirement benefit obligation	52.1	(45.7)

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act introduced a prescription drug benefit to retirees as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is actuarially equivalent to the benefit provided by Medicare. In January 2004, the FASB staff issued FASB Staff Position 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-1). FSP 106-1 allows sponsors of postretirement health care plans that provide a prescription drug benefit to make a one-time election to defer accounting for certain provisions of the Act until further authoritative guidance is issued by FASB. Alternatively, sponsors not electing the deferral option must account for the effects of the Act. We are required to make our election on whether we will defer accounting for the effects of the Act by the first quarter of 2004. We expect that we will not elect the deferral option but will account for the subsidy as a reduction of our accumulated postretirement benefit obligation with actuarial gain/loss treatment.

In accordance with the provisions of Statement 106, the Act had no effect on our reported 2003 accumulated postretirement benefit obligation, measured at September 30, 2003, or our 2003 net periodic postretirement benefit costs. We expect that the FASB will issue final authoritative guidance on accounting for the subsidy during 2004. Depending upon the timing of such guidance and our conclusion of whether or not to defer reflecting the effects of the Act, our net periodic postretirement benefit costs reported during the interim periods of 2004 could change.

In January 2004, we announced to employees the creation of a new retiree Health Reimbursement Account (HRA) option, which will impact the postretirement healthcare benefits provided by Cinergy. HRAs are bookkeeping accounts that can be used to pay for qualified medical expenses after retirement. The majority of employees will have the opportunity to make a one-time election to remain in our current retiree healthcare program or to move to the new HRA option. The HRA option has no effect on current retirees receiving postretirement benefits from Cinergy. As is the case under the current retiree health program, employees who participate in the HRA option will become eligible to receive their HRA benefit only upon retirement on or after the age of 50 with at least five years of service. We expect that the impact of the new HRA option will not be material to our other postretirement benefit costs.

10. Income Taxes

The following table shows the significant components of our net deferred income tax liabilities as of December 31:

(in millions)	2003	2002
Deferred Income Tax Liability		
Property, plant, and equipment	$1,524.8	$1,373.6
Unamortized costs of reacquiring debt	15.9	13.9
Deferred operating expenses and carrying costs	1.6	4.4
Purchased power tracker	3.9	11.6
RTC	204.2	213.2
Net energy risk management assets	10.0	8.8
Amounts due from customers-income taxes	47.6	37.4
Gasification services agreement buyout costs	85.8	89.8
Other	24.6	14.4
Total Deferred Income Tax Liability	1,918.4	1,767.1
Deferred Income Tax Asset		
Unamortized investment tax credits	39.3	42.5
Accrued pension and other postretirement benefit costs	195.6	196.3
Net energy risk management liabilities	8.8	–
Rural Utilities Service obligation	27.9	28.2
Tax credit carryovers	47.0	–
Other	41.8	41.9
Total Deferred Income Tax Asset	360.4	308.9
Net Deferred Income Tax Liability	$1,558.0	$1,458.2

We file a consolidated federal income tax return and combined/consolidated state and local tax returns in certain jurisdictions. Cinergy and its subsidiaries have an income tax allocation agreement, which conforms to the requirements of the PUHCA. The corporate taxable income method is used to allocate tax benefits to the subsidiaries whose investments or results of operations provide those tax benefits. Any tax liability not directly attributable to a specific subsidiary is allocated proportionately among the subsidiaries as required by the agreement.

The following table summarizes federal and state income taxes charged (credited) to income:

(in millions)	2003	2002	2001
Current Income Taxes			
Federal	$ 33.5	$ 16.3	$129.4
State	24.9	(4.1)	9.3
Total Current Income Taxes	58.4	12.2	138.7
Deferred Income Taxes			
Federal			
Depreciation and other property, plant, and equipment-related items(1)	129.4	172.2	42.7
Pension and other postretirement benefit costs	22.9	(17.4)	(11.8)
Deferred excise taxes	–	–	14.5
Unrealized energy risk management transactions	6.1	9.0	44.0
Fuel costs	7.2	(22.7)	5.7
Purchased power tracker	(4.6)	1.5	8.5
Gasification services agreement buyout costs	(3.2)	(2.6)	(2.2)
Tax credit carryovers	(47.0)	–	–
Other-net	(39.5)	(14.1)	10.9
Total Deferred Federal Income Taxes	71.3	125.9	112.3
State	21.7	30.4	15.4
Total Deferred Income Taxes	93.0	156.3	127.7
Investment Tax Credits-Net	(7.9)	(8.2)	(9.1)
Total Income Taxes	$143.5	$160.3	$257.3

(1) The increase from 2001 to 2002 in deferred income taxes for depreciation and other property, plant, and equipment-related items includes a change in accounting method for tax purposes related to capitalized costs.

Internal Revenue Code Section 29 provides a tax credit (nonconventional fuel source credit) for qualified fuels produced and sold by a taxpayer to an unrelated person during the taxable year. The nonconventional fuel source credit reduced current federal income tax expense $83.7 million, $41.6 million, and $1.1 million for 2003, 2002, and 2001, respectively.

The following table presents a reconciliation of federal income taxes (which are calculated by multiplying the statutory federal income tax rate by book income before federal income tax) to the federal income tax expense reported in the Statements of Income.

(in millions)	2003	2002	2001
Statutory federal income tax provision	\$186.0	\$185.7	\$235.3
Increases (reductions) in taxes resulting from:			
Amortization of investment tax credits	(7.9)	(8.2)	(9.1)
Depreciation and other property, plant, and equipment-related differences	4.3	0.2	3.2
Preferred dividend requirements of subsidiaries	1.2	1.2	1.2
Income tax credits	(83.7)	(41.6)	(2.1)
Foreign tax adjustments	5.1	3.2	(2.1)
Employee Stock Option Plan dividend	(6.5)	(3.0)	–
Other-net	(1.6)	(3.5)	6.2
Federal Income Tax Expense	\$ 96.9	\$134.0	\$232.6

11. Commitments and Contingencies

(A) ENVIRONMENTAL

(i) Ozone Transport Rulemakings

In June 1997, the Ozone Transport Assessment Group, which consisted of 37 states, made a wide range of recommendations to the U.S. Environmental Protection Agency (EPA) to address the impact of ozone transport on serious non-attainment areas (geographic areas defined by the EPA as non-compliant with ozone standards) in the Northeast, Midwest, and South. Ozone transport refers to wind-blown movement of ozone and ozone-causing materials across city and state boundaries.

1. Nitrogen Oxide (NO_X) State Implementation Plan (SIP) Call In October 1998, the EPA finalized its ozone transport rule, also known as the NO_X SIP Call. It applied to 22 states in the eastern half of the U.S., including the three states in which our electric utilities operate, and proposed a model NO_X emission allowance trading program. This rule recommended that states reduce NO_X emissions primarily from industrial and utility sources to a certain level by May 2003.

In August 2000, the U.S. Circuit Court of Appeals for the District of Columbia (Court of Appeals) extended the deadline for NO_X reductions to May 31, 2004. The states of West Virginia and Illinois, along with various industry groups (some of which we are a member), have challenged portions of the final rule in an action filed in the Court of Appeals. A decision is expected some time in the first quarter of 2004. It is unclear whether the Court of Appeals' decision in this matter will result in an increase or decrease in the size of the NO_X reduction requirement, or a deferral of the May 31, 2004 compliance deadline.

The states of Indiana and Kentucky developed final NO_X SIP rules in response to the NO_X SIP Call, through cap and trade programs, in June and July of 2001, respectively. The EPA has approved Indiana's and Kentucky's SIP rules, which have both become effective, and has conditionally approved Ohio's SIP rules. Ohio Environmental Protection Agency is still promulgating the changes to its rules to satisfy the EPA's conditions for approval. Our current plans for compliance with the EPA's NO_X SIP Call would also satisfy compliance with Indiana's, Kentucky's, and Ohio's SIP rules.

In September 2000, Cinergy announced a plan for its subsidiaries, CG&E and PSI, to invest in pollution control equipment and other methods to reduce NO_X emissions. This plan includes the following:

- install selective catalytic reduction units at several different generating stations;
- install other pollution control technologies, including new computerized combustion controls, at all generating stations;
- make combustion improvements; and
- utilize the NO_X allowance market to buy or sell NO_X allowances as appropriate.

The current estimate for additional expenditures for this plan is approximately \$104 million and is in addition to the \$685 million already incurred to comply with this program.

2. Section 126 Petitions In February 1998, several northeast states filed petitions seeking the EPA's assistance in reducing ozone in the Eastern U.S. under Section 126 of the Clean Air Act (CAA). The EPA believes that Section 126 petitions allow a state to claim that sources in another state are contributing to its air quality problem and request that the EPA require the upwind sources to reduce their emissions.

In December 1999, the EPA granted four Section 126 petitions relating to NO_X emissions. This ruling affected all of our Ohio and Kentucky facilities, as well as some of our Indiana facilities, and required us to reduce our NO_X emissions to a certain level by May 2003. The EPA subsequently extended the Section 126 rule compliance deadline to May 31, 2004, thus harmonizing the deadline with that for the NO_X SIP Call.

In April 2003, the EPA issued a proposed rule withdrawing the Section 126 rule in states with approved SIPs under the NO_X SIP Call, which include the states of Indiana and Kentucky. The proposed rule states that the EPA will withdraw the Section 126 rule in Ohio once Ohio has a fully approved SIP. As a result of these actions, we anticipate that the Section 126 rule will be withdrawn and, as a result, not affect any of our facilities.

(ii) Clean Air Act Lawsuit

In November 1999, and through subsequent amendments, the United States brought a lawsuit in the United States Federal District Court (District Court) for the Southern District of Indiana against Cinergy, CG&E, and PSI alleging various violations of the CAA. Specifically, the lawsuit alleges that we violated the CAA by not obtaining Prevention of Significant Deterioration (PSD), Non-Attainment New Source Review (NSR) and Ohio and Indiana SIP permits for various projects at our owned and co-owned generating stations. Additionally, the suit claims that we violated an Administrative Consent Order entered into in 1998 between EPA and Cinergy relating to alleged violations of Ohio's SIP provisions governing particulate matter at Unit 1 at CG&E's W.C. Beckjord Generating Station (Beckjord Station). The suit seeks (1) injunctive relief to require installation of pollution control technology on various generating units at CG&E's Beckjord Station and Miami Fort Generating Station (Miami Fort Station), and PSI's Cayuga Generating Station, Gallagher Generating Station, Wabash River Generating Station, and Gibson Generating Station (Gibson Station), and (2) civil penalties in amounts of up to $27,500 per day for each violation. In addition, three northeast states and two environmental groups have intervened in the case. The case is currently in discovery, and the District Court has set the case for trial by jury commencing in August 2005.

In March 2000, the United States also filed an amended complaint in a separate lawsuit alleging violations of the CAA relating to PSD, NSR, and Ohio SIP requirements regarding various generating stations, including a generating station operated by the Columbus Southern Power Company (CSP) and jointly-owned by CSP, the Dayton Power and Light Company (DP&L), and CG&E. The EPA is seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. This suit is being defended by CSP. In April 2001, the District Court in that case ruled that the Government and the intervening plaintiff environmental groups could seek injunctive relief for alleged violations that occurred more than five years before the filing of the complaint only. Thus, if the plaintiffs prevail in their claims, any calculation for penalties will not start on the date of the alleged violations, unless those alleged violations occurred after November 3, 1994, but CSP would be forced to install the controls required under the CAA. Neither party appealed that decision.

In addition, Cinergy and CG&E have been informed by DP&L that in June 2000, the EPA issued a Notice of Violation (NOV) to DP&L for alleged violations of PSD, NSR, and SIP requirements at a generating station operated by DP&L and jointly-owned by CG&E. The NOV indicated the EPA may (1) issue an order requiring compliance with the requirements of the SIP, or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation.

In December 2000, Cinergy, CG&E, and PSI reached an agreement in principle with the plaintiffs regarding the previously mentioned matters. The complete resolution of these issues was contingent upon establishing a final agreement with the EPA and other parties. Although we have continued to negotiate with the plaintiffs to achieve a final agreement, the plaintiffs have insisted on commitments from us which go beyond those contained in the agreement in principle. At this time we believe it is unlikely that a final settlement agreement will be reached on these terms. If a final settlement agreement is not reached, we intend to defend against the allegations, discussed above, vigorously in court. In such an event it is not possible to predict whether resolution of these matters would have a material effect on our financial position or results of operations.

(iii) Manufactured Gas Plant (MGP) Sites

Prior to the 1950s, gas was produced at MGP sites through a process that involved the heating of coal and/or oil. The gas produced from this process was sold for residential, commercial, and industrial uses.

Coal tar residues, related hydrocarbons, and various metals have been found at former MGP sites in Indiana, including at least 22 sites that PSI or its predecessors previously owned and sold in a series of transactions with Northern Indiana Public Service Company (NIPSCO) and Indiana Gas Company, Inc. (IGC).

In a combination of lawsuits and notices of violation, the 22 sites are in the process of being studied and will be remediated, if necessary. In 1998 NIPSCO, IGC, and PSI entered into Site Participation and Cost Sharing Agreements to allocate liability and responsibilities between them. The Indiana Department of Environmental Management (IDEM) oversees investigation and cleanup of all of these sites. Thus far, PSI has primary responsibility for investigating, monitoring and, if necessary, remediating nine of these sites. In December 2003, PSI entered into a voluntary remediation plan with the state of Indiana, providing a formal framework for the investigation and cleanup of the sites for which PSI has primary responsibility.

PSI notified its insurance carriers of the claims related to MGP sites raised by IDEM and costs included in the Site Participation and Cost Sharing Agreements. In April 1998, PSI filed suit in Hendricks County in the state of Indiana against its general liability insurance carriers. PSI sought a declaratory judgment to obligate its insurance carriers to (1) defend MGP claims against PSI and compensate PSI for its costs of investigating, preventing, mitigating, and remediating damage to property and paying claims related to MGP sites or (2) pay PSI's cost of defense. The trial court issued a variety of rulings with respect to the claims and defenses in the litigation. PSI appealed certain adverse rulings to the Indiana Court of Appeals and the appellate court has remanded the case to the trial court. A new trial date has yet to be scheduled. At the present time, PSI cannot predict the outcome of this litigation, including the outcome of the appeals.

PSI has accrued costs related to investigation, remediation, and groundwater monitoring for those sites where such costs are probable and can be reasonably estimated. We will continue to investigate and remediate the sites as outlined in the voluntary remediation plan. As additional facts become known and investigation is completed, we will assess if the likelihood of incurring additional costs becomes probable. Until all investigation and remediation is complete, we are unable to determine the overall impact on our financial position or results of operations.

CG&E has performed site assessments on its sites where we believe MGP activities have occurred at some point in the past and found no imminent risk to the environment.

(iv) Asbestos Claims Litigation

CG&E and PSI have been named as defendants or co-defendants in lawsuits related to asbestos at their electric generating stations. Currently, there are approximately 80 pending lawsuits. In these lawsuits, plaintiffs claim to have been exposed to asbestos-containing products in the course of their work at the CG&E and PSI generating stations. The plaintiffs further claim that as the property owner of the generating stations, CG&E and PSI should be held liable for their injuries and illnesses based on an alleged duty to warn and protect them from any asbestos exposure. A majority of the lawsuits to date have been brought against PSI. The impact on CG&E's and PSI's financial position or results of operations of these cases to date has not been material.

Of these lawsuits, one case filed against PSI has been tried to verdict. The jury returned a verdict against PSI in the amount of approximately $500,000 on a negligence claim and for PSI on punitive damages. PSI recently received an adverse ruling in an appeal of that verdict and is reviewing whether to appeal the verdict to the Indiana Supreme Court. In addition, we have settled a number of other lawsuits for amounts, which neither individually nor in the aggregate are material to CG&E's and PSI's financial position or results of operations.

At this time, CG&E and PSI are not able to predict the ultimate outcome of these lawsuits or the impact on CG&E's and PSI's financial position or results of operations.

(B) REGULATORY

(i) PSI Retail Electric Rate Case

In December 2002, PSI filed a petition with the IURC seeking approval of a base retail electric rate increase. PSI has filed initial and rebuttal testimony in this case and the final set of hearings took place in November 2003. PSI filed its proposed order in December 2003. Based on updated testimony filed in October 2003 and the proposed order, PSI proposes an increase in annual revenues of approximately $180 million, or an average increase of approximately 14 percent over PSI's retail electric rates in effect at the end of 2002. An IURC decision is anticipated by the end of the first quarter of 2004.

(ii) PSI Fuel Adjustment Charge

In June 2001, PSI filed a petition with the IURC requesting authority to recover $16 million in under billed deferred fuel costs incurred from March 2001 through May 2001. The IURC approved recovery of these costs subject to refund pending the findings of an investigative sub-docket. The sub-docket was opened to investigate the reasonableness of, and underlying reasons for, the under billed deferred fuel costs. A hearing was held in July 2002, and in March 2003 the IURC issued an order giving final approval to PSI's recovery of the $16 million.

(iii) PSI Construction Work in Progress (CWIP) Ratemaking Treatment for NO_X Equipment

In April 2003, PSI filed an application with the IURC requesting that its CWIP rate adjustment mechanism be updated for expenditures through December 2002 related to NO_X equipment currently being installed at certain PSI generation facilities. CWIP ratemaking treatment allows for the recovery of carrying costs on certain pollution control equipment while and after the equipment is under construction. A final order was issued in September 2003. The order granted substantially all of PSI's requested relief, leaving only the issue of whether certain specific equipment qualified for CWIP ratemaking treatment to be decided in the first half of 2004. This CWIP rate mechanism adjustment resulted in less than a one percent increase in customer rates.

In October 2003, PSI filed an application with the IURC requesting that its CWIP rate adjustment mechanism be updated for additional expenditures through September 30, 2003, related to NO_X equipment currently being installed at certain PSI generation facilities. If the application is approved, it will result in the recovery of an additional $7 million. An order on this third CWIP update case is expected in the first half of 2004.

PSI's initial CWIP rate mechanism adjustment (authorized in July 2002) resulted in an approximately one percent increase in customer rates. Under the IURC's CWIP rules, PSI may update its CWIP tracker at six-month intervals. The first such update to PSI's CWIP rate mechanism occurred in the first quarter of 2003. The IURC's July 2002 order also authorized PSI to defer, for subsequent recovery, post-in-service depreciation and to continue the accrual for AFUDC. Pursuant to Statement of Financial Accounting Standards No. 92, *Regulated Enterprises-Accounting for Phase-in Plans*, the equity component of AFUDC will not be deferred for financial reporting after the related assets are placed in service.

(iv) PSI Environmental Compliance Cost Recovery

In 2002, the Indiana General Assembly passed legislation that, among other things, encourages the deployment of advanced technologies that reduce regulated air emissions, while allowing the continued use of high sulfur Midwest coal in existing electric generating plants. The legislation authorizes the IURC to provide financial incentives to utilities that deploy such advanced technologies. PSI sought IURC approval, under this new law, of a cost tracking mechanism for PSI's NO_X equipment-related depreciation and operation and maintenance costs, authority to use accelerated (18-year) depreciation for its NO_X compliance equipment, and approval of a NO_X emission allowance purchase and sales tracker. In October 2003, PSI reached a settlement with the other parties to this case that provides for the relief described previously for most of PSI's environmental compliance equipment. In December 2003, the IURC approved the settlement agreement. Previously, the majority of these costs (the post-in-service depreciation costs) were being deferred pursuant to the July 2002 CWIP order described previously, and as a result, the settlement agreement did not have a material impact on PSI's results of operations or financial condition.

(v) PSI Purchased Power Tracker

The Tracker was designed to provide for the recovery of costs related to certain specified purchases of power necessary to meet native load customers' summer peak demand requirements to the extent such costs are not recovered through the existing fuel adjustment clause.

PSI is authorized to seek recovery of 90 percent of its purchased power expenses through the Tracker (net of the displaced energy portion recovered through the fuel recovery process and net of the mitigation credit portion), with the remaining 10 percent deferred for subsequent recovery in PSI's general retail electric rate case. In March 2002, PSI filed a petition with the IURC seeking approval to extend the Tracker process beyond the summer of 2002. A hearing was held in January 2003, and in June 2003 the IURC approved the extension for up to an additional two years with the ultimate determination concerning PSI's continued use of the Tracker process to be made in PSI's pending retail electric rate case.

In June 2002, PSI also filed a petition with the IURC seeking approval of the recovery through the Tracker of its actual summer 2002 purchased power costs. In May 2003, the IURC approved PSI's recovery of $18 million related to its summer 2002 purchased power costs, and also authorized $2 million of deferred costs sought for recovery in PSI's general retail electric rate case.

(vi) CG&E Transmission and Distribution Rate Filings

In October 2003, CG&E filed an application with the PUCO seeking deferral of approximately $173 million, of which approximately $42 million has been incurred as of December 31, 2003, in depreciation, property taxes and carrying costs related to net additions to transmission and distribution utility plant in service from January 2001 through December 2005. Rates are frozen in Ohio under the state's electric restructuring law from 2001 through the end of the market development period. CG&E has not deferred any of these costs as of December 31, 2003.

CG&E is proposing a mechanism to recover costs related to net additions to transmission and distribution utility plant in service after the end of the market development period. The mechanism would work in a similar manner to the monthly customer charge the PUCO approved for CG&E's accelerated natural gas main replacement program, discussed below in *(vii)*, which is adjusted annually based on expenditures in the previous year.

In the alternative electric reliability and rate stabilization proposal that CG&E filed in January 2004 with the PUCO, which is described in more detail in Note 17, CG&E made an alternative proposal to seek deferrals of transmission and distribution utility plant in service from January 2003 through December 2004, for the PUCO to declare an end to the market development period effective December 31, 2004, and for CG&E to file a transmission and distribution base rate case in 2004 to be effective January 1, 2005. The alternative proposal also includes tracking mechanisms as described in the preceding paragraph, which would recover ongoing transmission and distribution costs.

(vii) CG&E Gas Rate Case

In the third quarter of 2001, CG&E filed a retail gas rate case with the PUCO seeking to increase base rates for natural gas distribution service and requesting recovery through a tracking mechanism of the costs of an accelerated gas main replacement program with an estimated capital cost of $716 million over 10 years. An order was issued in May 2002, in which the PUCO authorized a base rate increase of approximately $15 million, or 3.3 percent overall, effective May 30, 2002. In addition, the PUCO authorized CG&E to implement the tracking mechanism to recover the costs of the accelerated gas main replacement program, subject to certain rate caps that increase in amount annually through May 2007, through the effective date of new rates in CG&E's next retail gas rate case. In April 2003, CG&E received approval to increase its rates under the tracking mechanism by $6.5 million. This increase was effective in May 2003. CG&E filed another application in January 2004 to increase its rates by approximately $7 million under the tracking mechanism. CG&E expects that the PUCO will rule on this application in the second quarter of 2004.

(viii) ULH&P Gas Rate Case

In the second quarter of 2001, ULH&P filed a retail gas rate case with the KPSC seeking to increase base rates for natural gas distribution services and requesting recovery through a tracking mechanism of the costs of an accelerated gas main replacement program with an estimated capital cost of $112 million over 10 years. Through December 31, 2003, ULH&P has recovered approximately $1.4 million under this tracking mechanism. The Kentucky Attorney General has appealed to the Franklin Circuit Court the KPSC's approval of the tracking mechanism and the KPSC's orders approving the new tracking mechanism rates. At the present time, ULH&P cannot predict the timing or outcome of this litigation.

(ix) Gas Distribution Plant

In June 2003, the PUCO approved an amended settlement agreement between CG&E and the PUCO Staff in a gas distribution safety case arising out of a gas leak at a service head-adapter (SHA) style riser on CG&E's distribution system. The amended settlement agreement required CG&E to expend a minimum of $700,000 to replace SHA risers by December 31, 2003, and to file a comprehensive plan addressing all SHA risers on its distribution system. Cinergy has an estimated 190,000 SHA risers on its distribution system, of which 155,000 are in CG&E's service area and 31,000 are in ULH&P's service area. Further investigation as to whether any additional SHA risers will need maintenance or replacement is ongoing. If CG&E and ULH&P determine that replacement of all SHA risers is appropriate, we currently estimate that the replacement cost could be up to approximately $70 million. CG&E and ULH&P would pursue recovery of this cost through rates. At this time, Cinergy, CG&E, and ULH&P cannot predict the outcome of this matter.

(C) OTHER

(i) Gas Customer Choice

In January 2000, Investments sold Cinergy Resources, Inc. (Resources), a former subsidiary, to Licking Rural Electrification, Inc., doing business as The Energy Cooperative (Energy Cooperative). In February 2001, Cinergy, CG&E, and Resources were named as defendants in three class action lawsuits brought by customers relating to Energy Cooperative's removal from the Ohio Gas Customer Choice program and the failure to deliver gas to customers. Subsequently, these class action suits were amended and consolidated into one suit. CG&E has been dismissed as a defendant in the consolidated suit. This customer litigation is pending in the Hamilton County Common Pleas Court. The trial court certified a class against CG&E in November 2003. A trial date has not been set.

In March 2001, Cinergy, CG&E, and Investments were named as defendants in a lawsuit filed by Energy Cooperative and Resources. This lawsuit concerns any obligations or liabilities Investments may have to Energy Cooperative following its sale of Resources. This lawsuit is pending in the Licking County Common Pleas Court. Trial is anticipated to occur in November 2004. In October 2001, Cinergy, CG&E, and Investments initiated litigation against the Energy Cooperative requesting indemnification by the Energy Cooperative for the claims asserted by former customers in the class action litigation. We intend to vigorously defend these lawsuits and do not believe their outcome will have a material effect on our financial position or results of operations.

(ii) Contract Disputes

Cinergy, through a subsidiary of Investments, has been involved in negotiations to resolve a customer billing dispute. The primary issue of contention between the parties related to the determinants used in calculating the monthly charge billed for electricity. Receivables from the customer have been recorded at their net realizable value and in January 2004, we settled the dispute. The impact of the settlement was not material to our financial position or results of operations.

Marketing & Trading was in arbitration with Apache Corporation (Apache) concerning disputes under an agreement whereby we marketed natural gas that Apache produced or acquired in North America. Effective July 1, 2003, Marketing & Trading terminated its marketing relationship with Apache. The termination of the marketing relationship ended the arbitration and all outstanding monetary issues related to the arbitration were settled. The impact of the settlement was not material to our financial position or results of operations.

(iii) Enron Bankruptcy

In December 2001, Enron filed for protection under Chapter 11 of the U.S. Bankruptcy Code in the Southern District of New York. We decreased our trading activities with Enron in the months prior to its bankruptcy filing and filed a motion with the bankruptcy court overseeing the Enron bankruptcy seeking appropriate netting of the various payables and receivables between and among Enron and Cinergy entities. Based on judicial decisions regarding the permissibility of certain broad netting arrangements and the results of our mediation, we entered into a settlement agreement with Enron, which became final on January 13, 2004. As a result of this agreement, we paid Enron approximately $14 million of which $12 million was charged to expense during the third quarter of 2003. We believe this resolves all of our claims with the Enron entities, except for one claim being handled outside the United States proceeding involving the recovery of an insignificant amount.

(iv) Synthetic Fuel Production

In July 2002, we acquired a coal-based synthetic fuel production facility. As of December 31, 2003, our net book value in this facility was approximately $60 million. The synthetic fuel produced at this facility qualifies for tax credits in accordance with Section 29 of the Internal Revenue Code. Eligibility for these credits expires after 2007. We received a private letter ruling from the IRS in connection with the acquisition of the facility. To date, we have produced and sold approximately 4.4 million tons of synthetic fuel at this facility, resulting in approximately $120 million in tax credits, including approximately $80 million in 2003.

In the second quarter of 2003, the IRS announced, as a result of an audit of another taxpayer, that it had reason to question and was reviewing the scientific validity of test procedures and results that were presented as evidence the fuel underwent a significant chemical change. The IRS recently announced that it has finished its review and has determined that test procedures and results used by taxpayers may be scientifically valid if the procedures are applied in a consistent and unbiased manner. The IRS also announced that it plans to impose new testing and record-keeping requirements on synthetic fuel producers and plans to issue guidance extending these requirements to taxpayers already holding private letter rulings on the issue of significant chemical change. We believe that any new testing or record-keeping requirements imposed by the IRS will not have a material effect on our financial position or results of operations.

(v) Energy Market Investigations

In July 2003, we received a subpoena from the Commodity Futures Trading Commission (CFTC). As has been previously reported by the press, the CFTC has served subpoenas on numerous other energy companies. The CFTC request sought certain information regarding our trading activities, including price reporting to energy industry publications. The CFTC sought particular information concerning these matters for the period May 2000 through January 2001 as to one of our employees. Based on an initial review of these matters, we placed that employee on administrative leave and have subsequently terminated his employment. We are continuing an investigation of these matters, including whether price reporting inconsistencies occurred in our operations, and have been cooperating fully with the CFTC.

In August 2003, Cinergy, along with 38 other companies, was named as a defendant in civil litigation filed as a purported class action on behalf of all persons who purchased and/or sold New York Mercantile Exchange natural gas futures and options contracts between January 1, 2000 and December 31, 2002. The complaint alleges that improper price reporting caused damages to the class. Two similar lawsuits have subsequently been filed, and these three lawsuits have been consolidated for pretrial purposes. Plaintiffs filed a consolidated class action complaint in January 2004. We believe this action is without merit and intend to defend this lawsuit vigorously; however, we cannot predict the outcome of this matter at this time.

In the second quarter of 2003, we received initial and follow-up third-party subpoenas from the SEC requesting information related to particular trading activity with one of our counterparties who was the target of an investigation by the SEC. We have fully cooperated with the SEC in connection with this matter. In January 2004, we received a grand jury subpoena from the Assistant United States Attorney in the Southern District of Texas for information relating to the same trading activities being investigated by the SEC. Specifically, the Assistant United States Attorney has requested information relating to communications between a former employee and another energy company. We understand that we are neither a target nor are we under investigation by the Department of Justice in relation to these communications.

At this time, it is not possible to predict the outcome of these investigations and litigation or their impact on our financial position or results of operations; although, in the opinion of management, they are not likely to have a material adverse effect on our financial position or results of operations.

(vi) Patents

Ronald A. Katz Technology Licensing, L.P. (RAKTL) has offered us a license to a portfolio of patents claiming that the patents may be infringed by certain products and services utilized by us. The patents purportedly relate to various aspects of telephone call processing in Cinergy call centers. As of this date, no legal proceedings have been instituted against us, but if the RAKTL patents are valid, enforceable and apply to our business, we could be required to seek a license from RAKTL or to discontinue certain activities. We are currently considering this matter, but lack sufficient information to assess the potential outcome at this time.

(vii) Guarantees

In the ordinary course of business, we enter into various agreements providing financial or performance assurances to third parties on behalf of certain unconsolidated subsidiaries and joint ventures. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to these entities on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish their intended commercial purposes. The guarantees have various termination dates, from short-term (less than one year) to open-ended.

In many cases, the maximum potential amount of an outstanding guarantee is an express term, set forth in the guarantee agreement, representing the maximum potential obligation of Cinergy under that guarantee (excluding, at times, certain legal fees to which a guaranty beneficiary may be entitled). In those cases where there is no maximum potential amount expressly set forth in the guarantee agreement, we calculate the maximum potential amount by considering the terms of the guaranteed transactions, to the extent such amount is estimable.

We have guaranteed the payment of $25 million as of December 31, 2003, for borrowings by individuals under the Director, Officer, and Key Employee Stock Purchase Program. We may be obligated to pay the debt's principal and any related interest in the event of an unexcused breach of a guaranteed payment obligation by certain directors, officers, and key employees. Most of the guarantees do not have a set termination date; however, the borrowings associated with the majority of the guarantees are due in the first quarter of 2005. Cinergy Corp. has also provided performance guarantees on behalf of certain unconsolidated subsidiaries and joint ventures. These guarantees support performance under various agreements and instruments (such as construction contracts, operations and maintenance agreements, and energy service agreements). Cinergy Corp. may be liable in the event of an unexcused breach of a guaranteed performance obligation by an unconsolidated subsidiary. Cinergy Corp. has estimated its maximum potential amount to be $104 million under these guarantees as of December 31, 2003. Cinergy Corp. may also have recourse to third parties for claims required to be paid under certain of these guarantees. The majority of these guarantees expire at the completion of the underlying performance agreement, the majority of which expire from 2016 to 2019.

We have entered into contracts that include indemnification provisions as a routine part of our business activities. Examples of these contracts include purchase and sale agreements and operating agreements. In general, these provisions indemnify the counterparty for matters such as breaches of representations and warranties and covenants contained in the contract. In some cases, particularly with respect to purchase and sale agreements, the potential liability for certain indemnification obligations is capped, in whole or in part (generally at an aggregate amount not exceeding the sale price), and subject to a deductible amount before any payments would become due. In other cases (such as indemnifications for willful misconduct of employees in a joint venture), the maximum potential amount is not estimable given that the magnitude of any claims under those indemnifications would be a function of the extent of damages actually incurred, which is not practicable to estimate unless and until the event occurs. We have estimated the maximum potential amount, where estimable, to be $115 million under these indemnification provisions. The termination period for the majority of matters provided by indemnification provisions in purchase and sale agreements generally ranges from 2004 to 2009.

We believe the likelihood that Cinergy would be required to perform or otherwise incur any significant losses associated with any or all of the guarantees described in the preceding paragraphs is remote.

(viii) Construction and Other Commitments

Forecasted construction and other committed expenditures, including capitalized financing costs, for the year 2004 and for the five-year period 2004-2008 (in nominal dollars) are $756 million and $4.1 billion, respectively. This forecast includes an estimate of expenditures in accordance with the companies' plans regarding environmental compliance.

12. Jointly-Owned Plant

CG&E, CSP, and DP&L jointly own electric generating units and related transmission facilities. PSI is a joint-owner of Gibson Station Unit No. 5 with Wabash Valley Power Association, Inc. (WVPA), and Indiana Municipal Power Agency (IMPA). Additionally, PSI is a joint-owner with WVPA and IMPA of certain transmission property and local facilities. These facilities constitute part of the integrated transmission and distribution systems, which are operated and maintained by PSI. The Statements of Income reflect CG&E's and PSI's portions of all operating costs associated with the jointly-owned facilities.

As of December 31, 2003, CG&E's and PSI's investments in jointly-owned plant or facilities were as follows:

(in millions)	Ownership Share	Property, Plant, and Equipment	Accumulated Depreciation	Construction Work in Progress
CG&E				
Production:				
Miami Fort Station (Units 7 and 8)	64.00%	$ 334	$132	$ 2
Beckjord Station (Unit 6)	37.50	45	28	1
Stuart Station(1)	39.00	308	156	75
Conesville Station (Unit 4)(1)	40.00	76	46	1
Zimmer Station	46.50	1,240	420	16
East Bend Station	69.00	392	193	3
Killen Station(1)	33.00	193	108	13
Transmission	Various	85	40	-
PSI				
Production:				
Gibson Station (Unit 5)	50.05	218	125	48
Transmission and local facilities	94.37	2,466	950	-

(1) Station is not operated by CG&E.

13. Quarterly Financial Data (unaudited)

(in millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2003					
Results of Operations:					
Operating Revenues(1)	$1,268	$ 934	$1,092	$1,122	$4,416
Operating Income	255	138	204	212	809
Income before discontinued operations and cumulative effect of changes in accounting principles	140	76	112	107	435
Discontinued operations, net of tax(2)	-	9	–	–	9
Cumulative effect of changes in accounting principles, net of tax(3)	26	–	–	–	26
Net Income	$ 166	$ 85	$ 112	$ 107	$ 470
Per Share Data:					
EPS					
Income before discontinued operations and cumulative effect of changes in accounting principles	0.81	0.42	0.63	0.60	2.46
Discontinued operations, net of tax(2)	–	0.05	–	–	0.05
Cumulative effect of changes in accounting principles, net of tax(3)	0.15	–	–	–	0.15
Net Income	$ 0.96	$0.47	$ 0.63	$ 0.60	$ 2.66
EPS — assuming dilution					
Income before discontinued operations and cumulative effect of changes in accounting principles	0.80	0.42	0.62	0.59	2.43
Discontinued operations, net of tax(2)	–	0.05	–	–	0.05
Cumulative effect of changes in accounting principles, net of tax(3)	0.15	-	–	–	0.15
Net Income	$ 0.95	$0.47	$ 0.62	$ 0.59	$ 2.63
2002					
Results of Operations:					
Operating Revenues(1)	$ 967	$ 907	$1,120	$1,065	$4,059
Operating Income	211	136	239	214	800
Income before discontinued operations and a cumulative effect of a change in accounting principle	95	45	132	125	397
Discontinued operations, net of tax(2)	1	–	(1)	(25)	(25)
Cumulative effect of a change in accounting principle, net of tax(4)	(11)	–	–	–	(11)
Net Income	$ 85	$ 45	$ 131	$ 100	$ 361
Per Share Data:					
EPS					
Income before discontinued operations and a cumulative effect of a change in accounting principle	0.57	0.27	0.79	0.74	2.37
Discontinued operations, net of tax(2)	0.01	–	(0.01)	(0.15)	(0.15)
Cumulative effect of a change in accounting principle, net of tax(4)	(0.06)	–	–	–	(0.06)
Net Income	$ 0.52	$0.27	$ 0.78	$ 0.59	$ 2.16
EPS — assuming dilution					
Income before discontinued operations and cumulative effect of a change in accounting principle	0.57	0.26	0.78	0.73	2.34
Discontinued operations, net of tax(2)	0.01	–	(0.01)	(0.15)	(0.15)
Cumulative effect of a change in accounting principle, net of tax(4)	(0.06)	–	–	–	(0.06)
Net Income	$ 0.52	$0.26	$ 0.77	$ 0.58	$ 2.13

(1) EITF 02-3 required that all gains and losses on energy trading derivatives be presented on a net basis beginning January 1, 2003. This resulted in substantial reductions in reported Operating Revenues, Fuel and purchased and exchanged power expense, and Gas purchased expense. However, Operating Income and Net Income were not affected by this change. For further information on EITF 02-3 see Note 1(Q)(i).

(2) See Note 14 for further explanation.

(3) Cinergy recognized a gain/(loss) on cumulative effect of changes in accounting principles of $39 million (net of tax) and ($13) million (net of tax) as a result of the reversal of accrued cost of removal for non-regulated generating assets and the change in accounting of certain energy related contracts from fair value to accrual. See Note 1(Q)(vi) for further information on the effects of changes in accounting principles.

(4) Upon implementation of Statement 142, Cinergy recognized a non-cash impairment charge of ($11) million, net of tax, for goodwill related to certain international assets. See Note 1(Q)(vi) for further information of the effect of a change in accounting principle.

14. Discontinued Operations

During 2002, we began taking steps to monetize certain non-core investments, including renewable and international investments within Commercial. During the second half of the year, we either sold or initiated plans to dispose of generation and electric and gas distribution operations in the Czech Republic, Estonia, and South Africa. We also sold investments, which were accounted for under the equity method, in renewable investments located in Spain and California. In total, we disposed of approximately $125 million of investments at a net loss, after-tax, of $7 million in 2002. Included in this net loss were cumulative foreign currency translation losses of approximately $4 million, after-tax.

During 2003, we completed the disposal of our gas distribution operation in South Africa, sold our remaining wind assets in the U.S., and substantially sold or liquidated the assets of our energy marketing business in the Czech Republic.

As a result of the 2003 transactions, assets of approximately $140 million have been sold or converted into cash and liabilities of approximately $100 million have been assumed by buyers or liquidated. The net, after-tax, gain from these disposal and liquidation transactions was approximately $9 million (including a net after-tax cumulative currency translation gain of approximately $6 million).

GAAP requires different accounting treatment for investment disposals involving entities which are consolidated and entities which are accounted for under the equity method. The consolidated entities have been presented as *Discontinued operations, net of tax* in our Statements of Income and as *Assets/Liabilities of Discontinued Operations* in our Balance Sheets. The accompanying financial statements and prior year financial statements have been reclassified to account for these entities as such. The disposal of the entities accounted for using the equity method are not allowed to be presented as discontinued operations. A gain of approximately $17 million on the sale of these entities is included in *Miscellaneous — Net* in our 2002 Statements of Income.

The table below reflects the assets and liabilities, the results of operations, and the income (loss) on disposal related to investments accounted for as discontinued operations for the years ended December 31, 2003 and 2002.

	December 31	
(in thousands)	**2003**	**2002**
Revenues[1]	$22,257	$ 95,493
Income (Loss) Before Taxes	$ 4,445	$(27,152)
Income Taxes Benefit (Expense)	$ 4,441	$ 1,991
Income (Loss) from Discontinued Operations		
Income (Loss) from operations, net of tax	$ 3	$ (829)
Gain (Loss) on disposal, net of tax[2]	8,883	(24,332)
Total Income (Loss) from Discontinued Operations	$ 8,886	$(25,161)
Assets		
Current assets	$ 4,501	$ 48,719
Property, plant, and equipment — net	–	78,309
Other assets	–	20,237
Total Assets	$ 4,501	$147,265
Liabilities		
Current liabilities	$11,594	$ 6,632
Long-term debt (including Long-term debt due within one year)	–	84,654
Other	–	17,547
Total Liabilities	$11,594	$108,833

(1) Presented for informational purposes only. All results of operations are reported net in our Statements of Income.

(2) For 2002, approximately $17 million of this amount represents a write-down to fair value, less cost to sell, on assets classified as held for sale at December 31, 2002. The remaining loss on disposal for 2002 represents actual losses on completed sales.

The losses included in the 2002 discontinued operations primarily pertain to two investments. In one case, the primary customer of a combined heat and power plant filed for bankruptcy resulting in a significant reduction in future expected revenues from the investment. This investment was sold in December 2002. In the second case, the retail market of a gas distribution business did not develop as expected, and we elected to exit the business rather than invest the additional capital which would be required to reach a sustainable level of market penetration. The investment was written down to its realizable value in December 2002 and was subsequently sold in April 2003.

15. Financial Information by Business Segment

We conduct operations through our subsidiaries and manage our business through the following three reportable segments:

- Commercial;
- Regulated Businesses; and
- Power Technology.

The following section describes the activities of our business units as of December 31, 2003.

Commercial manages wholesale generation and energy marketing and trading of energy commodities. Additionally, Commercial operates and maintains our electric generating plants including some of our jointly-owned plants. Commercial is also responsible for all of our international operations and performs energy risk management activities, trading activities, and customized energy solutions.

Regulated Businesses consists of PSI's regulated, integrated utility operations, and our other regulated electric and gas transmission and distribution systems. Regulated Businesses plans, constructs, operates, and maintains our transmission and distribution systems and delivers gas and electric energy to consumers. Regulated Businesses also earns revenues from wholesale customers primarily by transmitting electric power through our transmission system.

Power Technology primarily manages Cinergy Ventures, LLC (Ventures), our venture capital subsidiary. Ventures identifies, invests in, and integrates new energy technologies into our existing businesses, focused primarily on operational efficiencies and clean energy technologies. In addition, Power Technology manages our investments in other energy infrastructure and telecommunication service providers.

Following are the financial results by business unit. Certain amounts for the prior year have been restated to reflect implementation of EITF 02-3 and other prior year amounts have been reclassified to conform to the current presentation.

Financial results by business unit for the years ended December 31, 2003, 2002, and 2001, are as indicated below:

Business Units

	2003						
	Cinergy Business Units						
(in millions)	Commercial	Regulated Businesses	Power Technology	Total	All Other[1]	Reconciling Eliminations[2]	Consolidated
Operating revenues —							
External customers	$1,630	$2,786	$ –	$ 4,416	$ –	$ –	$ 4,416
Intersegment revenues	157	–	–	157	–	(157)	–
Cost of sales —							
Fuel and purchased and exchanged power							
External customers	645	513	–	1,158	–	–	1,158
Intersegment costs	–	157	–	157	–	(157)	–
Gas purchased	122	382	–	504	–	–	504
Depreciation[3]	135	284	–	419	–	–	419
Equity in earnings (losses) of unconsolidated subsidiaries	14	4	(3)	15	–	–	15
Interest expense[4]	94	158	17	269	–	–	269
Income taxes	7[5]	148	(11)	144	–	–	144
Discontinued operations, net of tax[6]	9	–	–	9	–	–	9
Cumulative effect of changes in accounting principles, net of tax[7]	26	–	–	26	–	–	26
Segment profit (loss)[8]	275	211	(16)	470	–	–	470
Segment assets from continuing operations	5,361	8,515	175	14,051	63	–	14,114
Segment assets from discontinued operations	5	–	–	5	–	–	5
Total segment assets	5,366	8,515[9]	175	14,056	63	–	14,119
Investments in unconsolidated subsidiaries	400	14	81	495	–	–	495
Total expenditures for long-lived assets	158	554	–	712	–	–	712

(1) The All Other category represents miscellaneous corporate items, which are not allocated to business units for purposes of segment performance measurement.

(2) The Reconciling Eliminations category eliminates the intersegment revenues of Commercial and the intersegment costs of Regulated Businesses.

(3) The components of Depreciation include depreciation of fixed assets and amortization of intangible assets.

(4) Interest income is deemed immaterial.

(5) The decrease in 2003, as compared to 2002, in part reflects the effect of tax credits associated with production of synthetic fuel beginning in July 2002.

(6) For further information, see Note 14.

(7) In 2003, Cinergy recognized a gain/(loss) on cumulative effect of changes in accounting principles of $39 million (net of tax) and $(13) million (net of tax) as a result of the reversal of accrued cost of removal for non-regulated generating assets and the change in accounting of certain energy related contracts from fair value to accrual. See Note 1(Q)(vi) for further information.

(8) Management utilizes Segment profit (loss), after taxes, to evaluate segment performance.

(9) The increase in 2003, as compared to 2002, is primarily due to the transfer of generating assets from two non-regulated affiliates. See Note 19 for further information.

Business Units (cont.)

	2002						
	Cinergy Business Units						
(in millions)	Commercial	Regulated Businesses	Power Technology	Total	All Other[1]	Reconciling Eliminations[2]	Consolidated
Operating revenues —							
External customers	$1,419	$2,640	$ –	$ 4,059	$ –	$ –	$ 4,059
Intersegment revenues	160	–	–	160	–	(160)	–
Cost of sales —							
Fuel and purchased and exchanged power							
External customers	532	458	–	990	–	–	990
Intersegment costs	–	160	–	160	–	(160)	–
Gas purchased	77	233	–	310	–	–	310
Depreciation[3]	150	249	6	405	–	–	405
Equity in earnings (losses) of unconsolidated subsidiaries	20	5	(10)	15	–	–	15
Interest expense[4]	102	133	8	243	–	–	243
Income taxes	23[5]	151	(14)	160	–	–	160
Discontinued operations, net of tax[6]	(25)	–	–	(25)	–	–	(25)
Cumulative effect of a change in accounting principle, net of tax[7]	(11)	–	–	(11)	–	–	(11)
Segment profit (loss)[8]	115	270	(24)	361	–	–	361
Segment assets from continuing operations	5,691	7,746	155	13,592	93	–	13,685
Segment assets from discontinued operations	147	–	–	147	–	–	147
Total segment assets	5,838	7,746	155	13,739	93	–	13,832
Investments in unconsolidated subsidiaries	337	10	70	417	–	–	417
Total expenditures for long-lived assets	188	681	1	870	–	–	870

(1) The All Other category represents miscellaneous corporate items, which are not allocated to business units for purposes of segment performance measurement.
(2) The Reconciling Eliminations category eliminates the intersegment revenues of Commercial and the intersegment costs of Regulated Businesses.
(3) The components of Depreciation include depreciation of fixed assets and amortization of intangible assets.
(4) Interest income is deemed immaterial.
(5) The decrease in 2002, as compared to 2001, in part reflects the effect of tax credits associated with production of synthetic fuel beginning in July 2002.
(6) For further information, see Note 14.
(7) Upon implementation of Statement 142, Cinergy recognized a non-cash impairment charge of $11 million, net of tax, for goodwill related to certain international assets. See Note 1(L) for further information.
(8) Management utilizes Segment profit (loss), after taxes, to evaluate segment performance.

Business Units (cont.)

	2001						
	Cinergy Business Units						
(in millions)	Commercial	Regulated Businesses	Power Technology	Total	All Other(1)	Reconciling Eliminations(2)	Consolidated
Operating revenues —							
External customers	$1,247	$2,703	$ –	$ 3,950	$ –	$ –	$ 3,950
Intersegment revenues	144	–	–	144	–	(144)	–
Cost of sales —							
Fuel and purchased and exchanged power							
External customers	546	469	–	1,015	–	–	1,015
Intersegment costs	–	144	–	144	–	(144)	–
Gas purchased	–	397	–	397	–	–	397
Depreciation(3)	130	236	1	367	–	–	367
Equity in earnings (losses) of							
unconsolidated subsidiaries	9	–	(8)	1	–	–	1
Interest expense(4)	108	142	9	259	–	–	259
Income taxes	93	169	(5)	257	–	–	257
Discontinued operations, net of tax(5)	(14)	–	–	(14)	–	–	(14)
Segment profit (loss)(6)	188	266	(12)	442	–	–	442
Segment assets from continuing operations	4,836	7,512	164	12,512	46	–	12,558
Segment assets from discontinued operations	234	–	–	234	–	–	234
Total segment assets	5,070	7,512	164	12,746	46	–	12,792
Investments in unconsolidated subsidiaries	256	–	76	332	–	–	332
Total expenditures for long-lived assets	764	633	–	1,397	–	–	1,397

(1) The All Other category represents miscellaneous corporate items, which are not allocated to business units for purposes of segment performance measurement.
(2) The Reconciling Eliminations category eliminates the intersegment revenues of Commercial and the intersegment costs of Regulated Businesses.
(3) The components of Depreciation include depreciation of fixed assets and amortization of intangible assets.
(4) Interest income is deemed immaterial.
(5) For further information, see Note 14.
(6) Management utilizes Segment profit (loss), after taxes, to evaluate segment performance.

(in millions)	Products and Services							
	Revenues							
	Utility			Wholesale Commodity				
Year	Electric	Gas	Total	Electric	Gas	Total	Other	Consolidated
2003	$2,156	$626	$2,782	$1,227	$210	$1,437	$197	$4,416
2002	2,197	436	2,633	1,141	154	1,295	131	4,059
2001	2,101	595	2,696	1,115	61	1,176	78	3,950

(in millions)	Geographic Areas		
	Revenues		
Year	Domestic	International	Consolidated
2003	$4,371	$45	$4,416
2002	4,011	48	4,059
2001	3,913	37	3,950

(in millions)	Long-Lived Assets		
Year	Domestic	International	Consolidated
2003	$11,524	$273	$11,797
2002	10,801	393	11,194
2001	10,174	428	10,602

16. Earnings Per Common Share

A reconciliation of EPS to EPS — assuming dilution is presented below:

(in thousands, except per share amounts)	Income	Shares	EPS
Year ended December 31, 2003			
EPS:			
Income before discontinued operations and cumulative effect of changes in accounting principles	$434,424		$ 2.46
Discontinued operations, net of tax	8,886		0.05
Cumulative effect of changes in accounting principles, net of tax	26,462		0.15
Net income	$469,772	176,535	$ 2.66
Effect of dilutive securities:			
Common stock options		746	
Directors' compensation plans		152	
Contingently issuable common stock		851	
Stock purchase contracts		189	
EPS — assuming dilution:			
Net income plus assumed conversions	$469,772	178,473	$ 2.63
Year ended December 31, 2002			
EPS:			
Income before discontinued operations and cumulative effect of a change in accounting principle	$396,636		$ 2.37
Discontinued operations, net of tax	(25,161)		(0.15)
Cumulative effect of a change in accounting principle, net of tax	(10,899)		(0.06)
Net income	$360,576	167,047	$ 2.16
Effect of dilutive securities:			
Common stock options		899	
Employee Stock Purchase and Savings Plan		3	
Directors' compensation plans		169	
Contingently issuable common stock		934	
EPS — assuming dilution:			
Net income plus assumed conversions	$360,576	169,052	$ 2.13
Year ended December 31, 2001			
EPS:			
Income before discontinued operations and cumulative effect of a change in accounting principle	$456,629		$ 2.87
Discontinued operations, net of tax	(14,350)		(0.09)
Net income	$442,279	159,110	$ 2.78
Effect of dilutive securities:			
Common stock options		975	
Directors' compensation plans		152	
Contingently issuable common stock		810	
EPS — assuming dilution:			
Net income plus assumed conversions	$442,279	161,047	$ 2.75

Options to purchase shares of common stock are excluded from the calculation of EPS — assuming dilution when the exercise price of these options plus unrecognized compensation expense is greater than the average market price of a common share during the period multiplied by the number of options outstanding at the end of the period because they are anti-dilutive. For the years 2003, 2002, and 2001, approximately 1.6 million, 3.0 million, and 2.1 million shares, respectively, were excluded from the EPS — assuming dilution calculation.

Also excluded from the EPS — assuming dilution calculation for the years ended December 31, 2003 and 2002, are up to 10.6 million and 10.8 million shares, respectively, issuable pursuant to the stock purchase contracts issued by Cinergy Corp. in December 2001 associated with the preferred trust securities transaction. The number of shares issuable pursuant to the stock purchase contracts is contingent upon the market price of Cinergy Corp. stock in February 2005 and could range between 9.2 and 10.8 million shares.

17. Deregulation

CG&E is in a market development period, transitioning to deregulation of electric generation and a competitive retail electric service market in the state of Ohio. The transition period is governed by the Amended Substitute Senate Bill No. 3 (Electric Restructuring Bill) and a stipulated transition plan adopted and approved by the PUCO. The Electric Restructuring Bill provides for a market development period that began January 1, 2001, and ends no later than December 31, 2005.

The major features of CG&E's transition plan include:

- Residential customer rates are frozen through December 31, 2005;
- Residential customers received a five-percent reduction in the generation portion of their electric rates, effective January 1, 2001;
- CG&E will provide $4 million from 2001 to 2005 in support of energy efficiency and weatherization services for low income customers;
- CG&E will provide shopping credits to switching customers;
- The creation of a RTC designed to recover CG&E's regulatory assets and other transition costs over a ten-year period;
- Authority for CG&E to transfer its generation assets to one or more, non-regulated affiliates to provide flexibility to manage its generation asset portfolio in a manner that enhances opportunities in a competitive marketplace;
- Authority for CG&E to apply the proceeds of transition cost recovery to costs incurred during the transition period, including implementation costs and purchased power costs that may be incurred by CG&E to maintain an operating reserve margin sufficient to provide reliable service to its customers;
- Authority for CG&E to adjust the amortization of its regulatory assets and other transition costs to reflect the effects of any shopping incentives provided to customers; and
- CG&E will provide standard offer default supplier service (i.e., CG&E will be the supplier of last resort, so that no customer will be without an electric supplier).

Under CG&E's transition plan, retail customers continue to receive transmission and distribution services from CG&E, but may purchase electricity from another supplier. Retail customers that purchase electricity from another supplier receive shopping credits from CG&E. The shopping credits generally reflect the costs of electric generation included in CG&E's frozen rates. However, shopping credits for the first 20 percent of electricity usage in each customer class to switch suppliers are higher than shopping credits for subsequent switchers in order to stimulate the development of the competitive retail electric service market.

CG&E recovers its generation-related regulatory assets and certain other deferred transition costs through an RTC paid by all retail customers. As the RTC is collected from customers, CG&E amortizes the deferred balance of regulatory assets and other transition costs. A portion of the RTC collected from customers is recognized currently as a return on the deferred balance of regulatory assets and other transition costs and as reimbursement for the difference in the shopping credits provided to retail customers and the wholesale revenues from generation made available by switched customers. The ability of CG&E to recover its regulatory assets and other transition costs is dependent on several factors, including, but not limited to, the level of CG&E's electric sales, prices in the wholesale power markets, and the amount of customers switching to other electric suppliers.

In January 2003, CG&E filed an application with the PUCO for approval of a methodology to establish how market-based rates for non-residential customers will be determined when the market development period ends. In the filing, CG&E seeks to establish a market-based standard service offer rate for non-residential customers that do not switch suppliers and a process for establishing the competitively-bid generation service option required by the Electric Restructuring Bill. As of December 31, 2002, more than 20 percent of the load of CG&E's commercial and industrial customer classes had switched to other electric suppliers, and the other public authorities group was at 19.95 percent at December 31, 2003. Under its transition plan, CG&E may end the market development period for those classes of customers once 20 percent switching has been achieved; however, PUCO approval of the standard service offer rate and competitive bidding process is required before the market development period can be ended.

In December 2003, the PUCO issued an order that the CG&E application filed in January 2003 would proceed to a hearing and be consolidated with CG&E's application to defer certain administrative transmission charges and the application to defer costs of capital investments made to their transmission and distribution system during the market development period. As part of this order, the PUCO requested that CG&E file a rate stabilization plan to mitigate the effects of market based pricing on retail customers while the competitive retail electric market continues to mature. In response to this request, on January 26, 2004, CG&E filed an offer of settlement, including an electric reliability and rate stabilization plan. In this proposal, CG&E has also asked to end the market development period for all customers effective December 31, 2004.

The major features of CG&E's electric reliability and rate stabilization plan include:

- The market development period would end for all customers on December 31, 2004;
- CG&E would begin to collect a non-bypassable Provider of Last Resort (POLR) charge from all customers effective January 1, 2005. This charge could be increased by up to 10 percent of CG&E's generation charge each year from 2005 through 2008;
- CG&E would offer its current generation rates as its market based rates until December 31, 2008;
- CG&E would request a transmission and distribution rate increase effective January 1, 2005;
- CG&E would begin charging RTC as an explicit wires charge;
- PUCO approval of previously requested transmission and distribution deferrals and cost recovery riders (see Note 11(B)*(vi)*);
- The five percent generation rate reduction for residential customers would continue through 2008;
- Extend recovery of residential RTC from 2008 through 2010.

The POLR charge would allow for recovery of increased costs of fuel and purchased power, transmission congestion, environmental compliance, homeland security, taxes and maintaining an adequate reserve margin.

An evidentiary hearing addressing these issues is scheduled for the second quarter of 2004. At the current time CG&E is unable to predict the outcome of this proceeding or the effects it could have on its results of operations or financial condition.

18. Comprehensive Income

Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to shareholders. The major components include net income, foreign currency translation adjustments, minimum pension liability adjustment, unrealized gains and losses on investment trusts and the effects of certain hedging activities.

We translate the assets and liabilities of foreign subsidiaries, whose functional currency (generally, the local currency of the country in which the subsidiary is located) is not the U.S. dollar, using the appropriate exchange rate as of the end of the year. Foreign currency translation adjustments are unrealized gains and losses on the difference in foreign country currency compared to the value of the U.S. dollar. The gains and losses are accumulated in comprehensive income. When a foreign subsidiary is substantially liquidated, the cumulative translation gain or loss is removed from comprehensive income and is recognized as a component of the gain or loss on the sale of the subsidiary in our Statements of Income.

We record a minimum pension liability adjustment associated with our defined benefit pension plans when the unfunded accumulated benefit obligation is in excess of our accrued pension liabilities and the unrecognized prior service costs recorded as an intangible asset. The corresponding offset is recorded on our Balance Sheets in *Accrued pension and other postretirement benefit costs*. Details of the pension plans' assets and obligations are explained further in Note 9.

We record unrealized gains and losses on equity investments in trusts we have established for our benefit plans. See Note 9 for further details.

The changes in fair value of derivatives that qualify as hedges, under Statement 133, are recorded in comprehensive income. The specific hedge accounting and the derivatives that qualify are explained in greater detail in Note 8(A).

The elements of comprehensive income and their related tax effects for the years ended December 31, 2003, 2002, and 2001 are as follows:

	Comprehensive Income								
	2003			2002			2001		
(dollars in thousands)	Before-tax Amount	Tax (Expense) Benefit	Net-of-Tax Amount	Before tax Amount	Tax (Expense) Benefit	Net-of-Tax Amount	Before-tax Amount	Tax (Expense) Benefit	Net-of-Tax Amount
Net income	$626,284	$(156,512)	$469,772	$518,840	$(158,264)	$360,576	$697,785	$(255,506)	$442,279
Other comprehensive income (loss):									
Foreign currency translation adjustment	25,311	(8,649)	16,662	35,574	(14,034)	21,540	4,996	(3,355)	1,641
Reclassification adjustments	(9,437)	3,303	(6,134)	4,377	–	4,377	–	–	–
Total foreign currency translation adjustment	15,874	(5,346)	10,528	39,951	(14,034)	25,917	4,996	(3,355)	1,641
Minimum pension liability adjustment	(56,238)	22,392	(33,846)	(23,031)	9,268	(13,763)	(2,636)	1,081	(1,555)
Unrealized gain (loss) on investment trusts	11,113	(4,356)	6,757	(8,637)	3,360	(5,277)	(1,345)	504	(841)
Cumulative effect of change in accounting principle	–	–	–	–	–	–	(4,026)	1,526	(2,500)
Cash flow hedges	2,516	(990)	1,526	(32,663)	12,915	(19,748)	(4,477)	1,698	(2,779)
Total other comprehensive income (loss)	(26,735)	11,700	(15,035)	(24,380)	11,509	(12,871)	(7,488)	1,454	(6,034)
Total comprehensive income	$599,549	$(144,812)	$454,737	$494,460	$(146,755)	$347,705	$690,297	$(254,052)	$436,245

The after-tax components of *Accumulated other comprehensive income (loss)* as of December 31, 2003, 2002, and 2001 are as follows:

	Accumulated Other Comprehensive Income (Loss) Classification				
(dollars in thousands)	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Unrealized Gain (Loss) on Investment Trusts	Cash Flow Hedges	Total Other Comprehensive Income (Loss)
Balance at December 31, 2000	$ (6,072)	$ (4,780)	$ (43)	$ –	$(10,895)
Cumulative effect of change in accounting principle	–	–	–	(2,500)	(2,500)
Current-period change	1,641	(1,555)	(841)	(2,779)	(3,534)
Balance at December 31, 2001	$ (4,431)	$ (6,335)	$ (884)	$ (5,279)	$(16,929)
Current-period change	25,917	(13,763)	(5,277)	(19,748)	(12,871)
Balance at December 31, 2002	$21,486	$(20,098)	$(6,161)	$(25,027)	$(29,800)
Current-period change	10,528	(33,846)	6,757	1,526	(15,035)
Balance at December 31, 2003	$32,014	$(53,944)	$ 596	$(23,501)	$(44,835)

19. Transfer of Generating Assets

In December 2002, the IURC approved a settlement agreement among PSI, the Indiana Office of the Utility Consumer Counselor, and the IURC Testimonial Staff authorizing PSI's purchases of the Henry County, Indiana and Butler County, Ohio, gas-fired peaking plants from two non-regulated affiliates. In February 2003, the FERC issued an order under Section 203 of the Federal Power Act authorizing PSI's acquisitions of the plants, which occurred on February 5, 2003. Subsequently, in April 2003, the FERC issued a tolling order allowing additional time to consider a request for rehearing filed in response to the February 2003 FERC order. At this time, the rehearing request is still pending before the FERC, and PSI cannot predict the outcome of this matter.

In July 2003, ULH&P filed an application with the KPSC requesting a certificate of public convenience and necessity to acquire CG&E's 68.9 percent ownership interest in the East Bend Generating Station, located in Boone County, Kentucky, the Woodsdale Generating Station, located in Butler County, Ohio, and one generating unit at the four-unit Miami Fort Station located in Hamilton County, Ohio. In December 2003, the KPSC conditionally approved this application. The transfer, which will be made at net book value, will not affect current electric rates for ULH&P's customers, as power will be provided under the same terms as under the current wholesale power contract with CG&E through at least December 31, 2006. ULH&P will also seek regulatory approval for aspects of this transaction from the FERC and SEC. At this time, ULH&P is unable to predict the outcome of this matter.

	2003	2002
Operating Revenues *(in thousands)*	$ 4,415,877	$ 4,059,352
Income Before Discontinued Operations and Cumulative Effect of Changes in Accounting Principles *(in thousands)*	434,424	396,636
Discontinued Operations, net of tax *(in thousands)*	8,886	(25,161)
Cumulative Effect of Changes in Accounting Principles, net of tax	26,462	(10,899)
Net Income *(in thousands)*	469,772	360,576
Construction Expenditures (including AFUDC) *(in thousands)*	711,649	866,193
Capitalization *(in thousands)*		
Common Equity	3,700,682	3,293,476
Preferred Stock[a]		
Subject to Mandatory Redemption	–	–
Not Subject to Mandatory Redemption	62,818	62,828
Preferred Trust Securities[e]	–	308,187
Long-term Debt[a]	4,131,909	4,011,568
Total Capitalization	$ 7,895,409	$ 7,676,059
Other Common Stock Data		
Avg. Shares Outstanding *(in millions)*	177	167
Avg. Shares Outstanding — Assuming Dilution *(in millions)*	178	169
Earnings Per Share		
Income Before Discontinued Operations and Cumulative Effect of Changes in Accounting Principles	$ 2.46	$ 2.37
Discontinued Operations, net of tax	0.05	(0.15)
Cumulative Effect of a Change in Accounting Principle, net of tax	0.15	(0.06)
Earnings Per Share Net Income	$ 2.66	$ 2.16
Earnings Per Share — Assuming Dilution		
Income Before Discontinued Operations and Cumulative Effect of Changes in Accounting Principles	$ 2.43	$ 2.34
Discontinued Operations, net of tax	0.05	(0.15)
Cumulative Effect of Changes in Accounting Principles, net of tax	0.15	(0.06)
Earnings Per Share — Assuming Dilution	$ 2.63	$ 2.13
Dividends Declared Per Share	$ 1.84	$ 1.80
Payout Ratio — Assuming Non-Dilution	69.2%	83.3%
Book Value Per Share *(year-end)*	$ 20.75	$ 19.53

Certain amounts in prior years have been reclassified to conform to the 2003 presentation.

(a) Excludes amounts due within one year.

(b) Includes $.12 per share for the cost of reacquiring 90% of CG&E's preferred stock through a tender offer.

(c) Includes $.69 per share for an extraordinary item (Midlands windfall profit tax).

(d) Includes $1.54 per share for a write-off of a portion of Zimmer Station.

(e) As a result of adopting Interpretation 45, we no longer consolidate the trust that held *Company obligated mandatorily redeemable, preferred trust securities of subsidiary, holding solely debt securities of the company.* This resulted in the removal of these securities from our 2003 Balance Sheet and the addition to long-term debt of a $319 million (net of discount) note payable that Cinergy Corp. owes to the trust.

2001	2000	1999	1998	1997	1996	1995	1994	1993
$ 3,949,576	$ 3,752,400	$3,426,647	$3,223,494	$3,227,627	$3,276,187	$3,023,431	$2,888,447	$2,833,440
456,629	400,684	401,527	260,968	253,238	334,797	347,182	191,142	62,547
(14,350)	(1,218)	2,114	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–
442,279	399,466	403,641	260,968	253,238	334,797	347,182	191,142	62,547(d)
841,321	534,976	378,432	370,277	328,153	324,238	326,869	486,734	563,355
2,941,459	2,788,961	2,653,721	2,541,231	2,539,200	2,584,454	2,548,843	2,414,271	2,221,681
–	–	–	–	–	–	160,000	210,000	210,000
62,833	62,834	92,597	92,640	177,989	194,232	227,897	267,929	307,989
306,327	–	–	–	–	–	–	–	–
3,532,556	2,828,792	2,966,842	2,604,467	2,150,902	2,326,378	2,346,766	2,615,269	2,545,213
$ 6,843,175	$ 5,680,587	$5,713,160	$5,238,338	$4,868,091	$5,105,064	$5,283,506	$5,507,469	$5,284,883
159	159	159	158	158	158	157	147	144
161	160	159	159	159	159	158	148	145
$ 2.87	$ 2.52	$ 2.53	$ 1.65	$ 1.61(c)	$ 2.00(b)	$ 2.22	$ 1.30	$ 0.43(d)
(0.09)	(0.01)	0.01	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–
$ 2.78	$ 2.51	$ 2.54	$ 1.65	$ 1.61(c)	$ 2.00(b)	$ 2.22	$ 1.30	$ 0.43(d)
$ 2.84	$ 2.51	$ 2.52	$ 1.65	$ 1.59(c)	$ 1.99(b)	$ 2.20	$ 1.29	$ 0.43(d)
(0.09)	(0.01)	0.01	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–
$ 2.75	$ 2.50	$ 2.53	$ 1.65	$ 1.59(c)	$ 1.99(b)	$ 2.20	$ 1.29	$ 0.43(d)
$ 1.80	$ 1.80	$ 1.80	$ 1.80	$ 1.80	$ 1.74	$ 1.72	$ 1.50	$ 1.46
64.7%	71.7%	70.9%	109.1%	111.8%	87.0%	77.5%	115.4%	339.5%
$ 18.45	$ 17.54	$ 16.70	$ 16.06	$ 16.10	$ 16.39	$ 16.17	$ 15.56	$ 15.17

	2003	2002
Degree Day Data		
Service Territory *(Avg.)*		
Heating (10 year average — 5,145)	5,316	5,093
Cooling (10 year average — 1,074)	831	1,357
Employee Data		
Number of Employees *(year-end)*	7,693	7,823
Gas Operations		
Gas Revenues *(in thousands)*		
Residential	$ 377,394	$ 253,470
Commercial	150,714	100,553
Industrial	25,922	17,214
Other	69,210	61,562
Total Retail	623,240	432,799
Wholesale/Storage and Transportation	210,031	154,832
Other	2,236	2,840
Total Gas Revenues	$ 835,507	$ 590,471
Gas Sales *(mcf)*		
Residential	39,353	35,615
Commercial	16,804	15,240
Industrial	3,112	2,927
Other	35,790	37,633
Total Retail	95,059	91,415
Wholesale/Storage and Transportation	1,421,091	1,252,783
Total Gas Sales	1,516,150	1,344,198
Gas Customers *(Avg.)*		
Residential	420,790	408,307
Commercial	39,980	38,942
Industrial	1,613	1,569
Other	42,555	50,154
Total Gas Customers	504,938	498,972
Avg. Cost Per Mcf Purchased *(cents)*(a)	611.44	395.99

Certain amounts in prior years have been reclassified to conform to the 2003 presentation.

(a) Excludes wholesale numbers.

2001	2000	1999	1998	1997	1996	1995	1994	1993
4,828	5,298	4,814	4,361	5,476	5,751	5,451	5,066	5,491
1,015	938	1,151	1,243	861	953	1,215	1,042	1,106
8,769	8,362	8,950	8,794	7,609	7,973	8,602	8,868	9,227
$ 349,346	$287,753	$210,557	$240,297	$284,516	$272,303	$237,576	$242,415	$269,684
148,206	110,329	85,169	87,583	121,345	118,994	99,708	114,854	114,957
28,761	17,784	13,797	17,320	31,168	30,409	28,979	43,490	47,403
60,679	69,406	61,098	52,589	49,190	46,409	39,588	35,673	31,551
586,992	485,272	370,621	397,789	486,219	468,115	405,851	436,432	463,595
60,701	51,909	57,732	45,954	30,212	1,403	1,086	1,306	1,353
7,985	2,902	3,769	2,755	3,106	4,517	3,915	4,660	4,348
$ 655,678	$540,083	$432,122	$446,498	$519,537	$474,035	$410,852	$442,398	$469,296
35,211	38,230	32,790	36,256	41,846	44,721	43,153	39,065	43,514
16,225	15,829	14,474	13,999	19,141	21,199	19,664	20,070	20,370
3,356	2,770	2,646	2,941	5,240	5,746	6,624	9,025	10,011
34,711	43,325	41,956	60,031	56,261	52,155	44,848	37,086	32,589
89,503	100,154	91,866	113,227	122,488	123,821	114,289	105,246	106,484
1,007,567	590,317	530,258	353,353	9,372	352	279	296	307
1,097,070	690,471	622,124	466,580	131,860	124,173	114,568	105,542	106,791
427,158	395,799	387,769	404,417	407,128	397,660	389,165	379,953	373,494
41,772	39,058	38,033	39,332	41,915	41,499	40,897	40,545	40,348
1,746	1,447	1,457	1,569	1,960	1,961	1,959	2,076	2,176
24,680	46,833	44,789	16,852	2,709	2,346	2,156	1,575	1,471
495,356	483,137	472,048	462,170	453,712	443,466	434,177	424,149	417,489
677.46	436.90	304.78	364.43	380.41	326.50	277.92	335.60	353.74

	2003	2002
Electric Operations		
Electric Revenues *(in thousands)*		
Residential	$1,147,236	$1,188,161
Commercial	728,818	776,846
Industrial	663,350	699,971
Transportation	25,527	13,560
Other	136,556	106,339
Total Retail	2,701,487	2,784,877
Wholesale	559,988	395,435
Other	121,657	157,756
Total Electric Revenues	$3,383,132	$3,338,068
Electric Sales *(million kWh)*		
Residential	16,368	17,088
Commercial	12,148	13,161
Industrial	16,553	17,473
Transportation	3,794	2,592
Other	2,471	1,811
Total Retail	51,334	52,125
Wholesale	164,595	138,897
Total Electric Sales	215,929	191,022
Electric Customers (Including Transportation) *(Avg.)*		
Residential	1,353,611	1,340,398
Commercial	165,140	164,657
Industrial	6,273	6,468
Other	10,477	8,178
Total Electric Customers	1,535,501	1,519,701
System Capability — Winter *(MW)*[a]		
Commercial	6,274[c]	7,107
Regulated Businesses	7,057[c]	6,004
Electricity Output *(million kWh)*		
Generated — Net		
Commercial	26,974	27,363
Regulated Businesses	34,270	33,060
Source of Energy Supply *(Capacity %)*		
Commercial		
Coal	66.72%	58.90%
Oil & Gas	33.28%	41.10%
Regulated Businesses		
Coal	77.76%	92.90%
Oil & Gas	21.60%	6.35%
Hydro	0.64%	0.75%
Fuel Cost		
Commercial		
Per MMBtu	$ 1.30	$ 1.32
Regulated Businesses		
Per MMBtu	$ 1.40	$ 1.35

Certain amounts in prior years have been reclassified to conform to the 2003 presentation.

(a) Includes amounts to be purchased, subject to availability, pursuant to agreements with other utilities.

(b) 1993 reflects the refund of $31 million applicable to the IURC's April 1990 rate order.

(c) Regulated Businesses purchased the Henry County, Indiana, and Butler County, Ohio, gas-fired peaking plants from Commerical in February 2003.

2001	2000	1999	1998	1997	1996	1995	1994	1993
$1,087,638	$1,088,998	$1,127,289	$1,028,314	$ 984,891	$ 996,959	$ 965,278	$ 898,763	$ 893,089
782,282	775,201	754,965	722,292	689,091	673,181	661,496	626,333	608,407
710,587	720,610	725,641	702,208	669,464	657,563	637,090	598,126	584,382
2,798	–	–	–	–	–	–	–	–
110,885	106,899	117,284	100,017	111,867	110,003	118,458	96,247	68,364(b)
2,694,190	2,691,708	2,725,179	2,552,831	2,455,313	2,437,706	2,382,322	2,219,469	2,154,242
441,470	372,185	192,406	129,393	208,423	296,600	197,943	194,734	177,754
79,992	52,455	49,035	46,399	38,488	34,400	32,314	31,846	32,148
$3,215,652	$3,116,348	$2,966,620	$2,728,623	$2,702,224	$2,768,706	$2,612,579	$2,446,049	$2,364,144(b)
15,794	15,633	16,069	14,551	14,147	14,705	14,366	13,578	13,818
13,607	13,596	13,102	12,524	12,034	11,802	11,648	11,167	10,963
18,022	19,008	18,830	18,093	17,321	16,803	16,264	15,547	14,860
613	–	–	–	–	–	–	–	–
1,720	1,891	1,939	1,815	1,825	1,811	1,795	1,723	1,732
49,756	50,128	49,940	46,983	45,327	45,121	44,073	42,015	41,373
119,938	69,831	49,883	77,759	57,454	12,399	7,769	7,801	7,063
169,694	119,959	99,823	124,742	102,781	57,520	51,842	49,816	48,436
1,329,708	1,304,893	1,280,658	1,257,853	1,236,974	1,215,782	1,195,323	1,174,705	1,160,513
163,528	159,965	156,897	153,674	151,093	149,015	147,888	144,766	142,767
6,562	6,507	6,486	6,473	6,472	6,470	6,424	6,345	6,263
7,601	7,060	6,639	6,395	6,280	6,184	5,955	5,733	5,678
1,507,399	1,478,425	1,450,680	1,424,395	1,400,819	1,377,451	1,355,590	1,331,549	1,315,221
7,084	–	–	–	–	–	–	–	–
6,004	11,249	11,221	11,221	11,221	11,221	11,351	11,181	11,181
24,955	–	–	–	–	–	–	–	–
33,627	63,010	59,389	56,920	54,850	52,659	52,458	50,330	49,078
59.10%	–	–	–	–	–	–	–	–
40.90%	–	–	–	–	–	–	–	–
92.90%	86.80%	86.77%	86.77%	86.77%	86.77%	85.78%	85.57%	85.57%
6.35%	12.80%	12.83%	12.83%	12.83%	12.83%	13.82%	14.03%	14.03%
0.75%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
$ 1.39	–	–	–	–	–	–	–	–
$ 1.31	$ 1.25	$ 1.26	$ 1.25	$ 1.31	$ 1.30	$ 1.40	$ 1.44	$ 1.47

QUARTERLY STOCK DATA

Quarter	1st	2nd	3rd	4th
2003				
High	$35.87	$38.75	$36.99	$38.86
Close	33.65	36.79	36.70	38.81
Low	29.77	33.25	33.14	35.19
Dividends per share	.46	.46	.46	.46
2002				
High	$35.75	$37.19	$36.21	$34.19
Close	35.75	35.99	31.43	33.72
Low	31.00	34.25	25.40	28.25
Dividends per share	.45	.45	.45	.45

CORPORATE HEADQUARTERS

Cinergy Corp.
139 East Fourth Street
Cincinnati, Ohio 45202
Web site: www.cinergy.com

ANNUAL MEETING

The annual meeting of shareholders will be held at the
Northern Kentucky Convention Center
One West Rivercenter Boulevard
Covington, Kentucky
on Tuesday, May 4, 2004,
at 9:00 a.m. Eastern Daylight Time.

COMMON STOCK

Cinergy's common stock, traded under the ticker symbol CIN, is listed on the New York Stock Exchange. Cinergy has unlisted trading privileges on the Boston, Chicago, Cincinnati, Pacific and Philadelphia exchanges. As of Jan. 31, 2004, there were 52,506 common stock shareholders of record.

FORM 10-K

Shareholders may obtain a copy of Cinergy's annual report to the Securities and Exchange Commission (Form 10-K), without charge, by contacting Investor Relations or by visiting our Web site at: www.cinergy.com/investors.

REINVESTMENT PLAN INQUIRIES

National City Bank
Reinvestment Services-Loc. 5352
P.O. Box 94946
Cleveland, Ohio 44101-4946
Toll-free phone: 1-800-325-2945
Fax: (216) 257-8367

OTHER SHAREHOLDER ACCOUNT INQUIRIES

National City Bank
Shareholder Services-Loc. 5352
P.O. Box 92301
Cleveland, Ohio 44101-4301
Toll-free phone: 1-800-325-2945
Fax: (216) 257-8508

E-mail address for all services:
shareholder.services@nationalcity.com

INVESTOR CONTACT

Brad Arnett
Director, Investor Relations
139 East Fourth Street 26AT
Cincinnati, Ohio 45202
(513) 287-3024
Fax: (513) 287-1088
E-mail: barnett@cinergy.com

DIRECT STOCK PURCHASE AND DIVIDEND REINVESTMENT

Cinergy's Direct Stock Purchase and Dividend Reinvestment Plan provides investors with a convenient method to purchase shares of Cinergy Corp. common stock and to reinvest cash dividends in the purchase of additional shares of Cinergy Corp. common stock, without incurring brokerage fees. Shareholders may automatically reinvest all or a portion of their cash dividends in Cinergy common stock at prevailing market prices.

Shareholders may also purchase additional shares by making payments of at least $25 at any one time, but not more than $100,000 per calendar year. Currently, there are about 31,850 shareholders participating in the plan.

The plan is open to anyone wishing to participate. Those who do not currently own shares on the company's records must complete an enrollment form and make an initial minimum investment of $250. An election form must be completed by anyone who wishes to change dividend reinvestment participation.

Complete details about the plan are contained in the plan's prospectus. To receive a copy of the prospectus and an enrollment form, contact National City Bank.

DIRECT DEPOSIT OF DIVIDENDS

Shareholders can have their dividends electronically transferred to their checking or savings accounts. To receive an enrollment form, contact National City Bank.

OTHER INFORMATION

Transfer agent and registrar for Cinergy Corp. common and CG&E and PSI preferred shares:
National City Bank
Stock Transfer Dept.-Loc. 5352
P.O. Box 92301
Cleveland, Ohio 44193-0900

DESIGN: PROWOLFF PARTNERS PHOTOGRAPHY: FERGUSON-KATZMAN

CINERGY®
the power of change

Cinergy Corp.
139 East Fourth Street
Cincinnati, Ohio 45202
www.cinergy.com

Cinergy Corp. has a balanced, integrated portfolio consisting of two core businesses: regulated operations and commercial businesses. Cinergy's regulated delivery operations in Ohio, Indiana, and Kentucky serve 1.5 million electric customers and about 500,000 gas customers. In addition, its Indiana regulated operations own 7,000 megawatts of generation. Cinergy's commercial business unit is a Midwest leader in low-cost generation owning 6,300 megawatts of capacity with a profitable balance of stable existing customer portfolios, new customer origination, marketing and trading, and industrial-site cogeneration. The "into Cinergy" power-trading hub is the most liquid trading hub in the nation.