10 CFR 50.71(b), 10 CFR 72.80(b)

Progress Energy

PO Box 1551
411 Fayetteville Street Mall
Raleigh NC 27602

Serial: PE&RAS-06-027
April 20, 2006

United States Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, DC 20555-0001

Director, Spent Fuel Project Office
Office of Nuclear Material Safety and Safeguards
United States Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, DC 20555-0001

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324 / LICENSE NOS. DPR-71 AND DPR-62

CRYSTAL RIVER UNIT 3 NUCLEAR GENERATING PLANT
DOCKET NO. 50-302 / LICENSE NO. DPR-72

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT NO. 1
DOCKET NO. 50-400 / LICENSE NO. NPF-63

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261 / LICENSE NO. DPR-23

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
INDEPENDENT SPENT FUEL STORAGE FACILTY
DOCKET NO. 72-3 / LICENSE NO. SNM-2502

SUBMITTAL OF LICENSEE ANNUAL FINANCIAL REPORT

Ladies and Gentlemen:

Pursuant to 10 CFR 50.71(b) and 10 CFR 72.80(b), Carolina Power & Light Company, now doing business as Progress Energy Carolinas, Inc. (PEC), and Florida Power Corporation, now doing business as Progress Energy Florida, Inc. (PEF) submit the enclosed Annual Report, including certified financial statements.

This document contains no new regulatory commitment.

If you have additional questions, please call me at (919) 546-6901.

Sincerely,

Chris Burton

Chris Burton
Manager - Performance
Evaluation & Regulatory Affairs

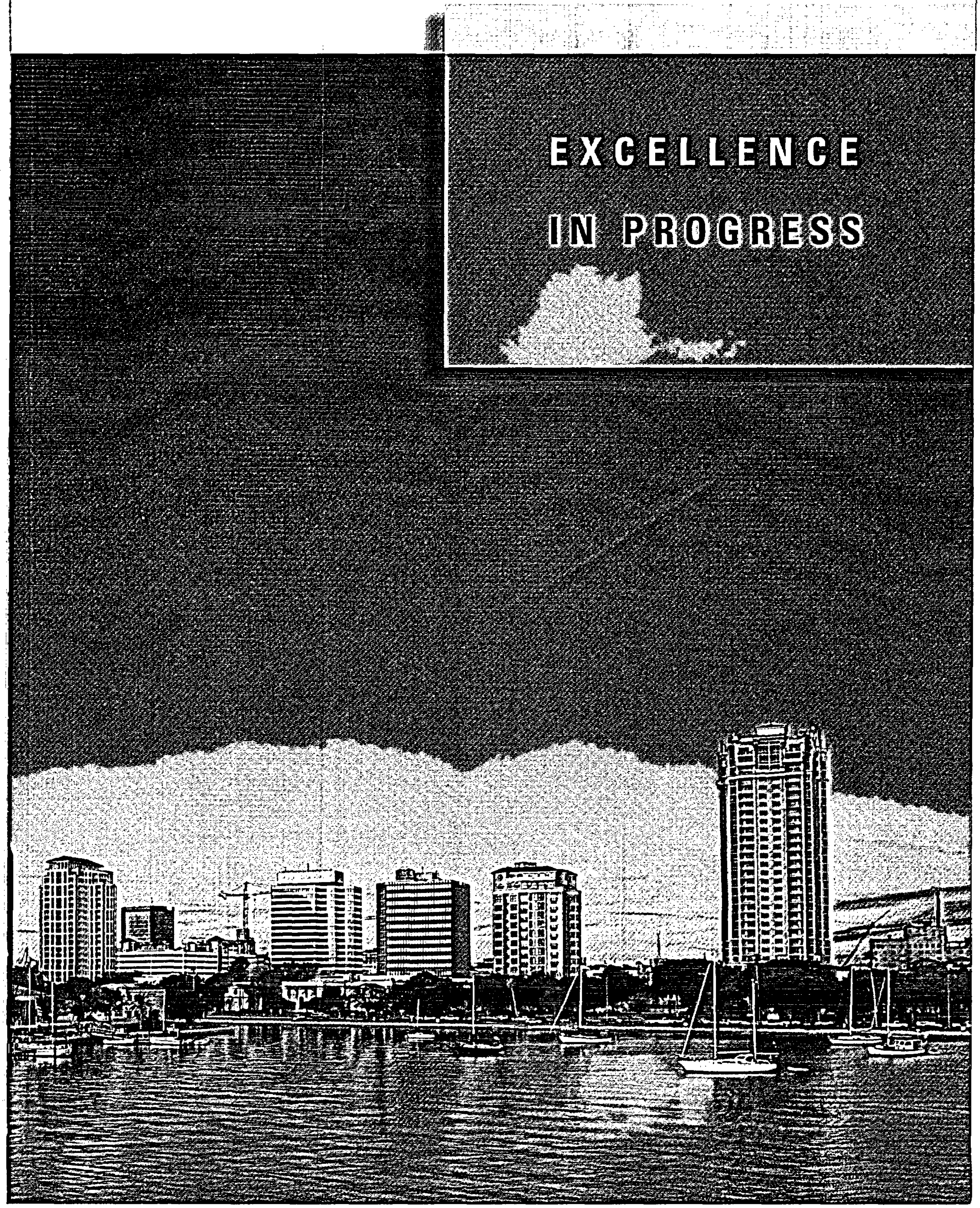
M004

DMF
Enclosure

c: W. D. Travers, Regional Administrator – Region II
USNRC Resident Inspector – BSEP, Unit Nos. 1 and 2
USNRC Resident Inspector – CR3
USNRC Resident Inspector – SHNPP, Unit No. 1
USNRC Resident Inspector – HBRSEP, Unit No. 2
B. L. Mozafari, NRR Project Manager – BSEP, Unit Nos. 1 and 2; CR3
C. P. Patel, NRR Project Manager – SHNPP, Unit No. 1; HBRSEP, Unit No. 2
J. A. Sanford – North Carolina Utilities Commission
R. Vance – North Carolina Utilities Commission
S. Watson – North Carolina Utilities Commission
B. O. Hall – North Carolina Department of Environment and Natural Resources

Progress Energy ANNUAL REPORT 2005

EXCELLENCE IN PROGRESS

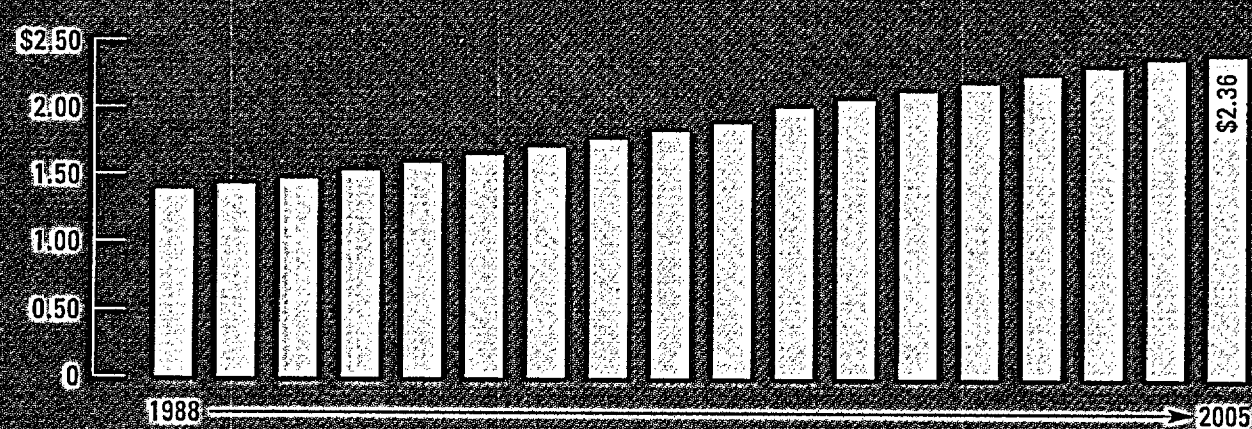


FINANCIAL HIGHLIGHTS

Years ended December 31 (in millions, except per share data)	2005	2004*	2003*
FINANCIAL DATA			
Operating revenues	**$10,108**	$8,525	$7,799
Net income	**697**	759	782
Income from continuing operations	**727**	729	811
Ongoing earnings per common share**	**3.33**	2.96	3.51
Reported GAAP earnings per common share	**2.82**	3.13	3.30
Average common shares outstanding	**247**	242	237
COMMON STOCK DATA			
Return on average common stock equity (percent)	**8.91**	9.99	11.07
Book value per common share	**$32.35**	$31.39	$30.94
Market value per common share (closing)	**$43.92**	$45.24	$45.26

**Financial data has been restated for discontinued operations.*
***See page 126 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*

18 YEARS OF DIVIDEND GROWTH



"At Progress Energy, we pursue excellence every day – excellence in the reliable power and service we provide our customers, the value for our shareholders and the opportunities for our employees. As we work to meet the needs of our growing service areas, we will continue to accept nothing less."

– Robert B. McGehee, Chairman and Chief Executive Officer

EXCELLENCE IN 2005 AND BEYOND

Robert B. McGehee –
Chairman and Chief Executive Officer

Dear Shareholders:

We are executing our long-term strategy well at Progress Energy and are placing the company in a strong position for continued success for our customers, shareholders and employees.

In 2005, we increased our dividend for the 18th consecutive year, exceeded our earnings target, streamlined our management structure, implemented a voluntary enhanced retirement program, and resolved key regulatory issues. At the same time, we added to our record of excellence in operations, service and customer satisfaction.

To strengthen our corporate balance sheet and focus on our core energy business, we sold Progress Rail for $405 million early in 2005. Because of this and other actions, such as utility regulatory agreements on cost recovery, Standard and Poor's revised its negative outlook on our credit rating to stable.

Building on Strengths

During 2006, we will continue to focus on improving our financial flexibility and credit quality. We are planning to divest our coal mines and are evaluating other noncore assets as part of our debt-reduction strategy. We remain committed to growing our core business earnings per share at 3 percent to 5 percent a year, which will enable us to sustain dividend growth.

We have not been satisfied with our stock price the last couple of years, but Progress Energy has sound fundamentals, growing utility service territories, a good strategy and a proven ability to deliver on its commitments. We believe that in time the market will reflect our strong position and positive momentum.

Early in 2006, we received a very favorable ruling from the IRS that concluded the long-unresolved audits of our Earthco synthetic fuel plants. This positive development removed a major uncertainty from the company.

Business Units on the Right Path

Our two electric utilities achieved very good results in 2005, including continued growth and record reliability. Progress Energy Carolinas, which serves areas of North Carolina and South Carolina, added 30,000 new retail customers during the year and increased wholesale sales. Progress Energy Florida added 43,000 retail customers while increasing wholesale sales. It also achieved a rate settlement that provides base rate stability through mid-2010, and received a ruling that permits recovery of 2004 hurricane costs.

(Letter continued inside)

One option we're exploring is to expand our nuclear generation in the Carolinas and Florida. Final decisions will depend on many factors, including public and political support, regulatory approval and forecasts for energy demand. Meanwhile, we are evaluating other generation options, aggressively pursuing energy-efficiency initiatives and supporting alternative energy technologies, including solar and hydrogen applications.

Another way we're preparing for the future is by actively engaging in the important issue of global climate change. Even with the scientific uncertainties that remain, we believe there is sufficient understanding of climate change to warrant action by both the public and private sectors, including our company. In March 2006, we issued a special report on the climate change issue (available at progress-energy.com). We are committed to working with stakeholders to develop consensus-based strategies to address the issue and help our region be successful as government policies unfold.

Excellence in Progress

At Progress Energy, we are relentless about achieving excellence and are building momentum in the right direction – for our customers, who depend on us for reliable, affordable power; for our shareholders, who have placed their trust in us as a buy-and-hold stock they can count on; and for our employees, who want to grow and contribute as part of a thriving company.

Excellence is in progress here. I am enthusiastic about our company's future and grateful to everyone at Progress Energy for working so hard each day to earn the confidence of the many people who rely on us.

Robert B. McGehee

Robert B. McGehee

Chairman and Chief Executive Officer

Central to our success at both utilities is our focus on continually improving the daily fundamentals of our business, which include safety, operational performance, cost efficiency and customer satisfaction.

In 2005, we became the first utility in the nation to receive the J.D. Power Founder's Award, which recognizes commitment to customer satisfaction. We also received the ServiceOne award from the global consulting firm PA Consulting Group for outstanding customer service.

As a way to use technology to improve both service and efficiency, we began installing an automated mobile metering system for our residential customers last year in the Carolinas and Florida. This will enable us to collect meter data quickly and accurately and at significantly lower cost.

Our diverse mix of power plants continues to perform well for us and our customers. We are aggressively managing our fuel costs, especially in this time of high commodity prices, to mitigate the rate impact on customers and the financial risk to the company.

Our nuclear generation fleet continues to rank among the best-performing in the country in terms of safety, production and cost. Four of our five nuclear units set production records last year. In addition, several of our fossil-fueled plants received top national honors in 2005 for reliability and cost efficiency from the Electric Utility Cost Group, a global industry association. We earned the top two rankings in the large plant category and the top four rankings in the small plant category.

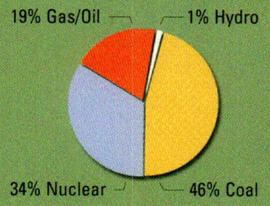
As for our Progress Ventures business unit, we continue to work on increasing the value of these unregulated assets. Competitive Commercial Operations, which has 3,100 megawatts of unregulated generation and is active in the southeastern U.S. wholesale market, added new contracts with other utilities in 2005 and is seeking additional market opportunities this year. Winchester Energy Company, the natural gas exploration and production unit of Progress Ventures, with assets in Texas and Louisiana, increased its proven gas reserves by more than 30 percent last year and plans to drill 70 or more new gas wells in 2006.

Preparing for the Future

As we take care of today at Progress Energy, we are also preparing for tomorrow in a region of the country that continues to see robust population growth and economic activity.

We are pursuing a balanced solution to meet the greater electricity needs caused by this growth and to continue reliable, affordable service. This multipronged approach includes smart ways to expand our energy-efficiency initiatives as well as a variety of ways to increase our generating capacity.

Fuel diversity for affordable, reliable power.



Our diverse generation mix allows us to weather price volatility and environmental challenges more effectively.

Top industry rankings for our fossil-fueled plants.

In 2005, we received top national honors for reliability and cost efficiency from the Electric Utility Cost Group.

Among the country's best performing nuclear plants.

Progress Energy's nuclear fleet continues to earn top rankings for production, safety and cost efficiency, with four units setting operational records in 2005.

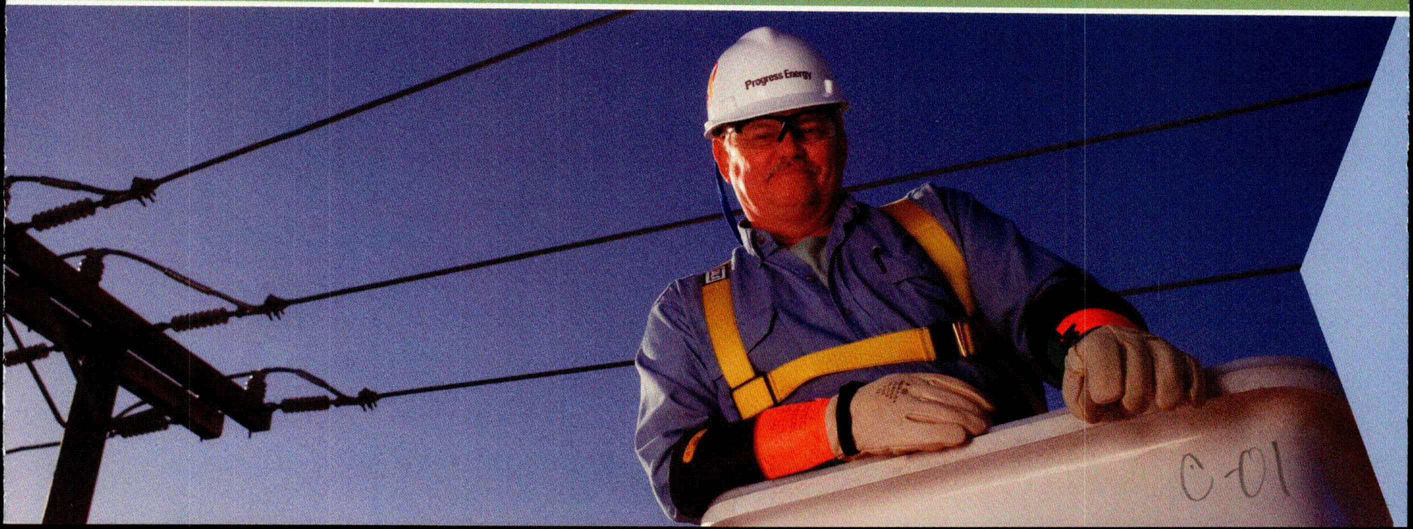
An integrated regulated electric utility is a complex business – from generating power efficiently to maintaining a strong transmission and distribution system to meeting customers' needs. Pursuing excellence in every aspect of operations has long been the key to Progress Energy's success. Our company's high standards and the ability to meet – and exceed – expectations contributed to a strong performance in 2005 and position us well for the years ahead.

A critical component of operational excellence is plant performance. By consistently operating plants safely and efficiently, Progress Energy delivers reliable power to customers and value to our shareholders. We constantly push ourselves to higher standards and, as a result, have seen consistent, measurable improvements in reliability, cost efficiency and overall performance each year.

In 2005, we aggressively managed fuel expenditures, holding spending increases to 12 percent despite landmark escalations in market prices, and thereby mitigating the effect on customers and risk to investors.

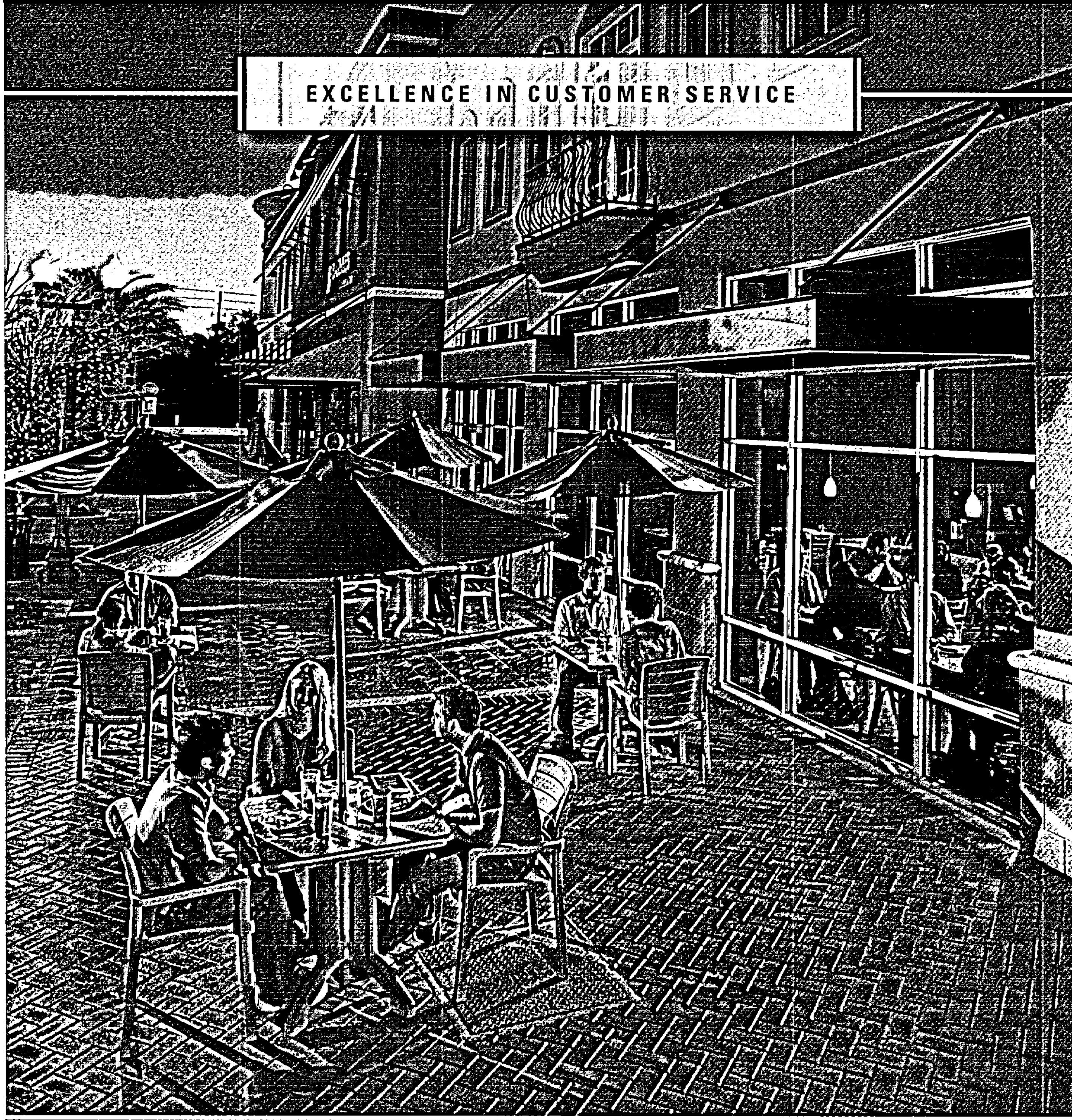
In addition, we continued making significant improvements throughout our system, including a new program of automated mobile meter reading that is expected to ultimately reduce costs by $21 million a year, while providing more accuracy and convenience for customers.

Looking ahead to 2006 and beyond, Progress Energy will continue to focus on understanding the growing needs of our customers and communities – because that's the best way to deliver outstanding reliability to customers and shareholders alike.



"No matter how well we perform, we constantly set the bar higher as we work to meet the growing needs of our customers. We are always looking for better ways to provide the most reliable power in the safest, most efficient way possible."

– Rick Thompson, Distribution Line and Service
North Central Region, Fla.



"We're here to ensure that our customers have the most reliable, affordable power possible, along with the service and support they need. We work with both our residential and commercial customers to help them improve their efficiency and manage their energy spending."

– Jean Belyeu, Energy Efficiency Services
Lake Mary, Fla.

Providing reliable electricity is where we begin, but Progress Energy's commitment to excellence doesn't stop there. Understanding our customers – from residential to commercial – and the realities of their specific needs is a key component of our daily mission and our overall success.

Winning awards does not drive our strategy, but it does confirm that we are focused on what matters most to our customers. In 2005, Progress Energy became the first utility to win the J.D. Power Founder's Award for excellence in customer satisfaction. This award is a tribute to our employees and to our customer-centered philosophy of collaboration, personal responsibility and innovation.

We understand that earning customers' trust goes beyond responding to their calls. In the face of rising energy costs, the company increased efforts in 2005 to help customers manage their energy spending through online services and bill-paying options. We initiated more energy-efficiency communications and performed individual energy audits for more than 46,000 customers, including small and large businesses, to help them increase efficiency and decrease costs. In addition to improving customer satisfaction, these efforts help us manage our generation capacity needs and perform more cost effectively over time.

As our customer base continues to grow, we will continue to strive to exceed expectations every day. Customer satisfaction is, and will always be, critical to our company's success.

Our customers first, in every kind of weather.

Progress Energy has won the Edison Electric Institute Award for outstanding storm response a record five times.

Award-winning support for others in need.

In 2005, we won our first Edison Electric Institute Support Award for providing assistance to customers of other utilities after Hurricanes Katrina, Rita and Wilma.

Setting new standards in customer satisfaction.

J.D. Power Founder's Award

Sustainable communities drive the future.

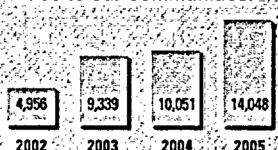
In 2005, we were named to the Dow Jones Sustainability Index as an industry leader for our business approach to economic, environmental and social issues.

Today's students are tomorrow's leaders.

We donated over $6 million in 2005 to educational initiatives that helped to build a better future for students from kindergarten through college.

Creating a stronger economic future.

Our economic development partnerships and initiatives play an important role in bringing jobs and opportunities to our communities.



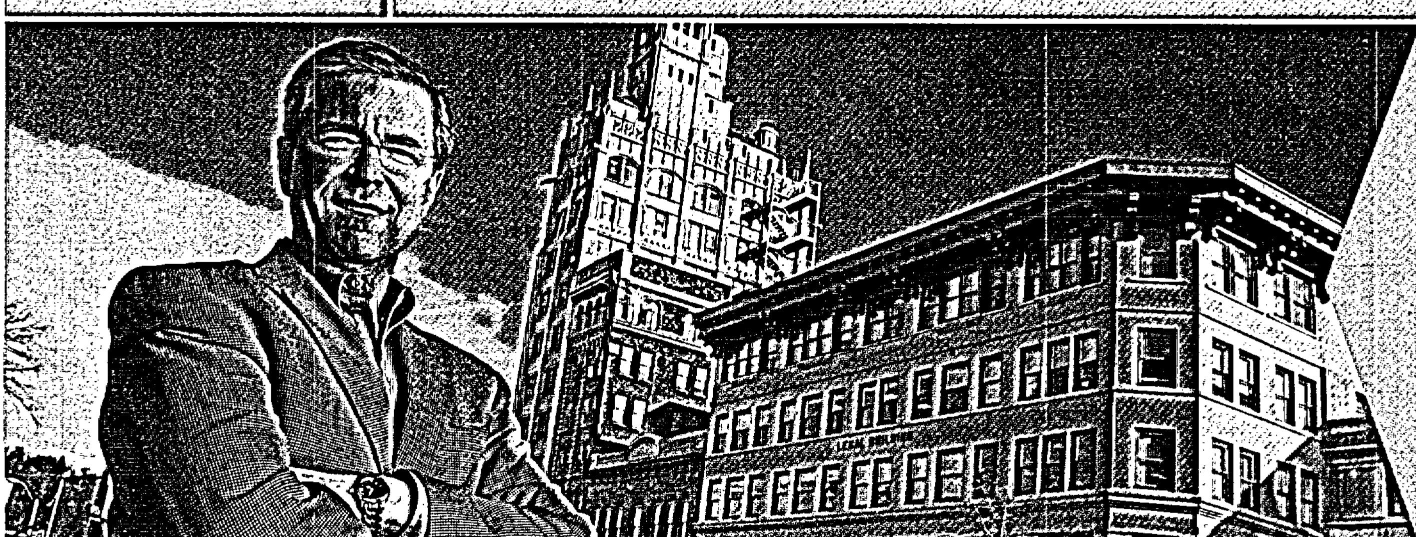
Jobs we've helped create

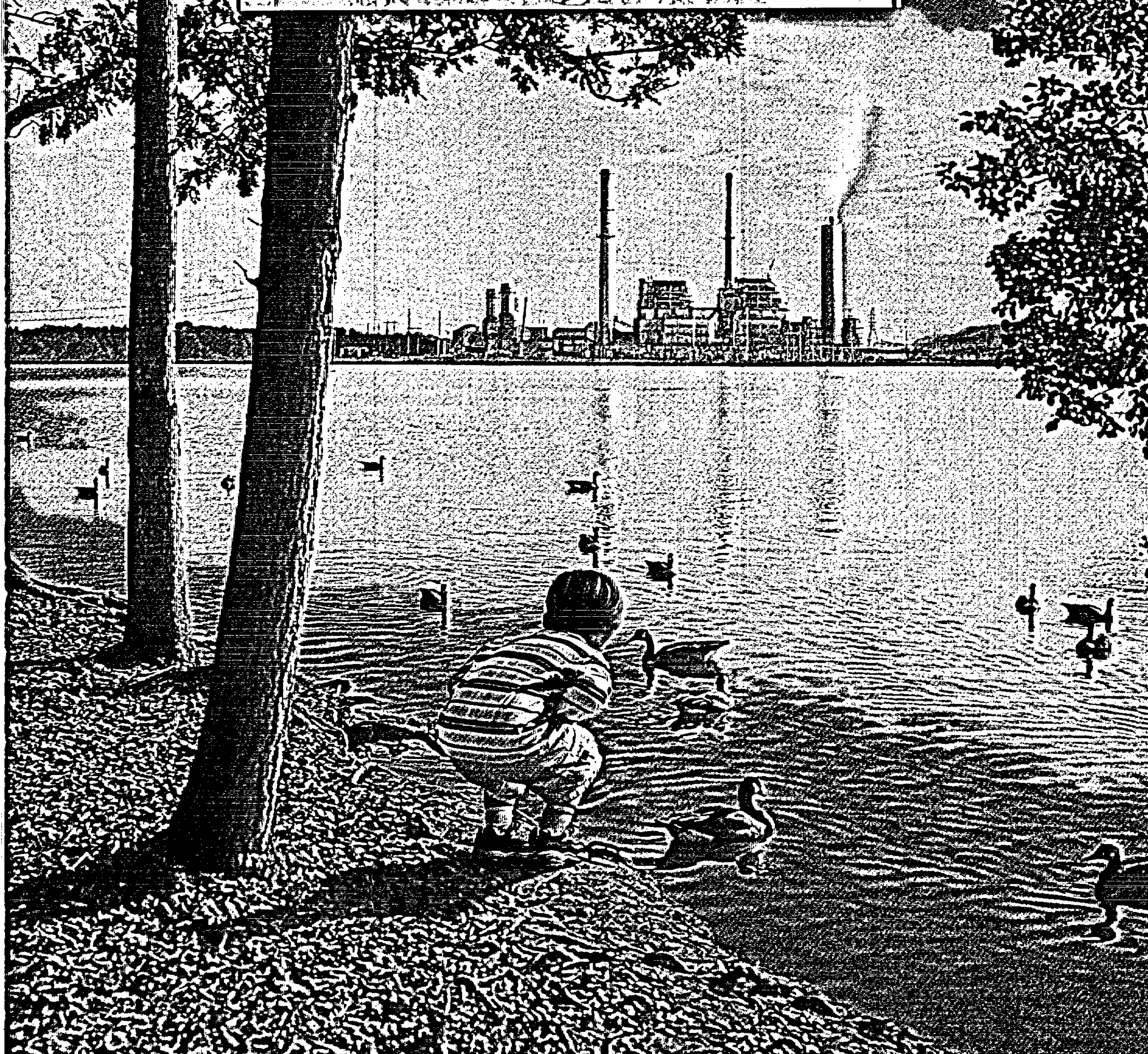
Progress Energy's success is linked with that of our communities. We consider investments in the community to be an important part of our mission.

We are fortunate to be located in a thriving region of the country, but location alone cannot ensure long-term growth. That's why the company actively partners with state and local officials to recruit new businesses – which in turn bring new jobs and an overall boost to the local economy. These efforts ensure a better future for everyone in our service area while also developing long-range growth for our own company. In 2005, our efforts helped to create more than 14,000 jobs and to bring more than $1.5 billion in new capital investment to our territories.

We are equally committed to enriching the environmental health and vitality of our communities. In 2005, we initiated a breakthrough for clean air by bringing our first "scrubber" into operation. This technology removes sulfur dioxide from a plant's emissions and is the first of several we plan to install. In addition, we are currently investing in other technologies in North Carolina that will significantly reduce sulfur dioxide and nitrogen oxide emissions from our coal-fired power plants throughout the state.

We also invest in numerous nonprofits and educational organizations that are making a difference in our communities for our employees and customers alike. In short, Progress Energy pursues excellence for our service areas as relentlessly as we pursue excellence in the delivery of safe, reliable power. And we're making a difference every day for the people who live here – and the future we all share.





"We are only as strong as the communities we serve. So it makes sense for us to work with them to help bring in new jobs, provide a cleaner environment and support a better quality of life in the places we call home."

– Ken Maxwell, Community Relations
Western Region, N.C.

"Planning well for the future might be one of the most important things we do. Every day, we use our experience and expertise to evaluate generation capacity, fuel mix, environmental issues and many other factors to ensure a continued future of reliable and cost-effective power."

– Curtis Lloyd, Energy Control Center
Raleigh, N.C.

Electricity is an integral part of our lives, and the backbone of the economy. Each of us is increasingly dependent on safe, reliable and cost-effective electricity in our homes and businesses.

At Progress Energy, we are committed to meeting our customers' growing need for electricity as well as the rising demand that results from population growth. Last year, we gained 73,000 new customers, and we expect more than 600,000 additional customers over the next 10 years.

To meet this increased demand, Progress Energy is working now to ensure an adequate power supply for the future. Many factors – such as environmental issues, fuel costs and the changing needs of our communities – must be weighed. Even after those decisions are made, new power plants require many years for planning and design, licensing and approvals, and construction.

Another critical component of our planning for the future is assessing the potential of new technology and alternative fuel sources to meet tomorrow's energy needs. Through corporate partnerships and investments, Progress Energy is exploring many forms of alternative energy, including hydrogen, biomass and solar. In today's world of volatile fuel prices, limited resources and increasing environmental regulations, such investments of our time and resources can only benefit our customers and our company.

Though all these decisions will be complex, our vision for the future is simple: to pursue excellence in all endeavors. That is how we'll deliver value to our customers, our shareholders and our employees, today and every day into the future.

Investing in the future.

Ensuring reliable power for the future requires a multipronged approach. We are currently evaluating and investing in many renewable and alternative energy sources, including:

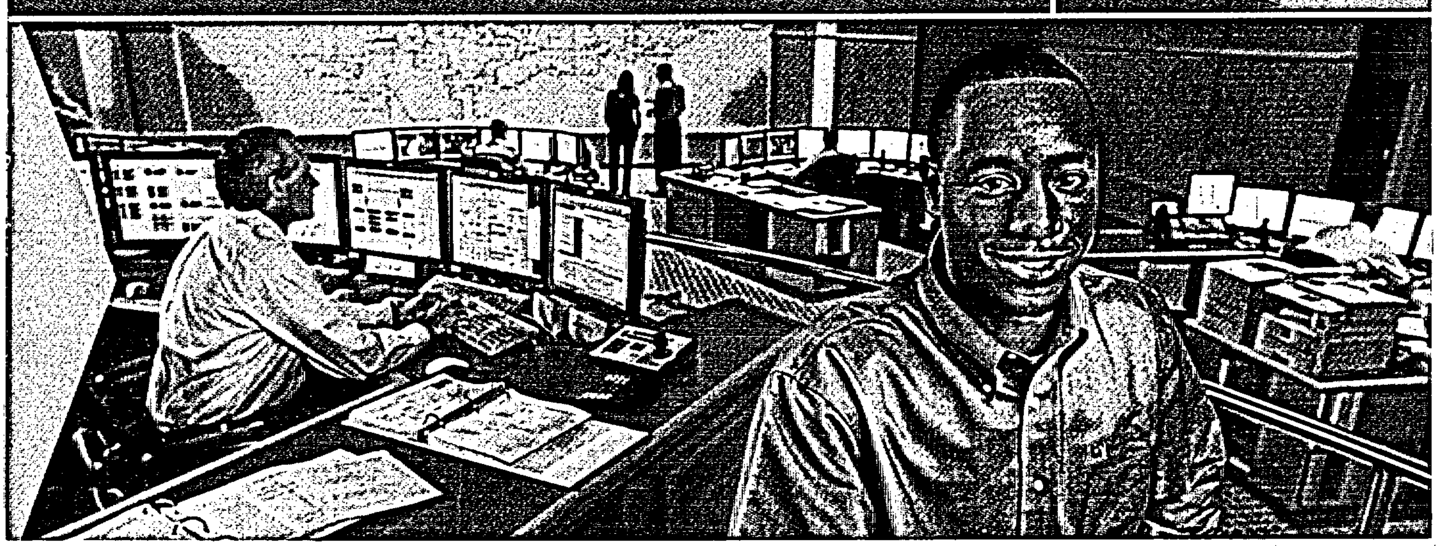
- Biomass
- Hydrogen fuel cells
- Solar photovoltaic systems
- Clean coal technologies
- Hydrogen-based automobiles and fueling stations

The Progress Energy-Ford partnership hydrogen fuel-cell vehicle

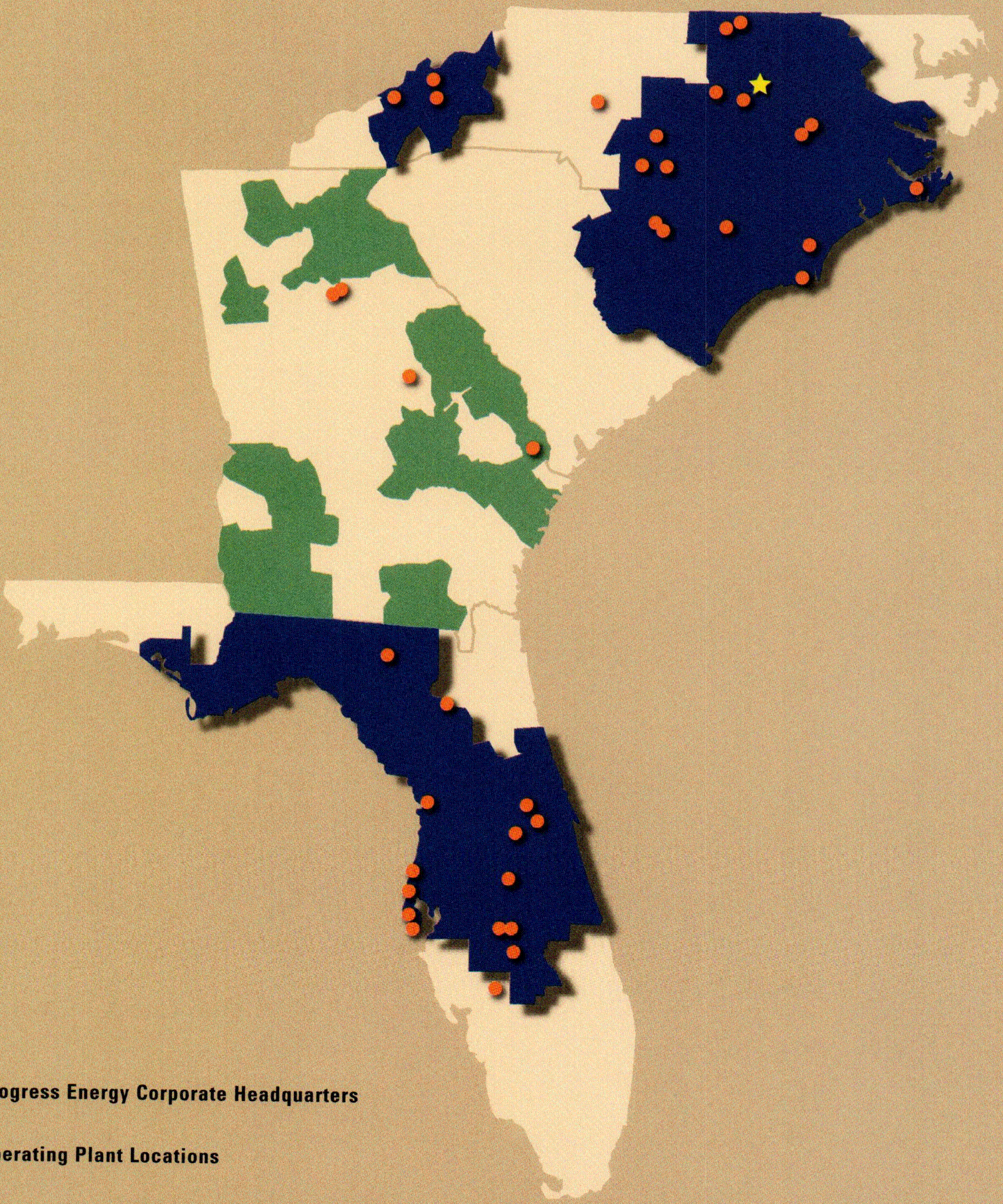
Managing demand.

Progress Energy is taking aggressive steps to expand energy efficiency and demand side management choices for customers.

These programs have reduced electric usage by more than 26 billion kWh since 1981.



OUR SERVICE TERRITORY: LOCATED IN ONE OF THE COUNTRY'S FASTEST-GROWING REGIONS.



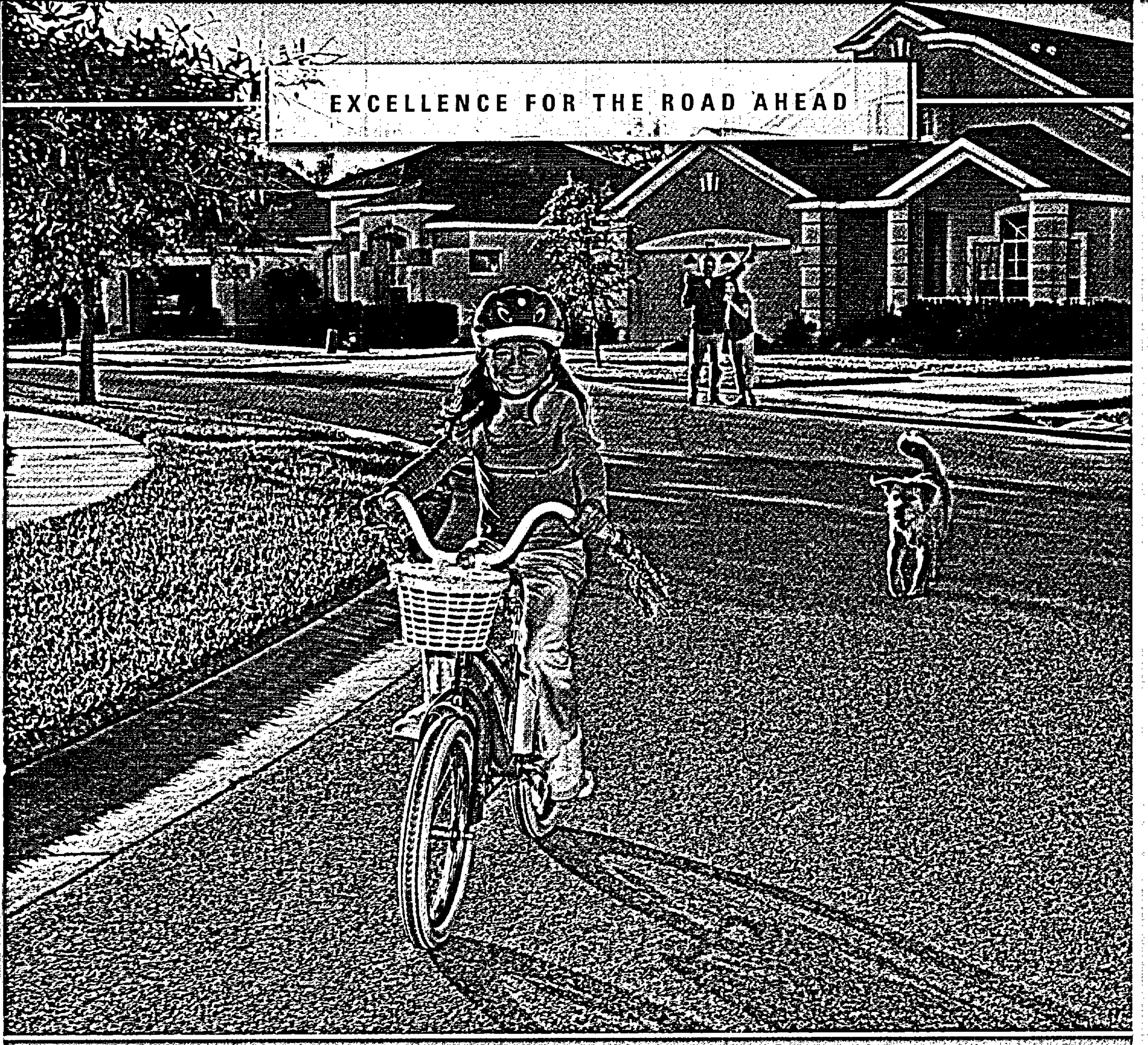
Progress Energy Corporate Headquarters

Operating Plant Locations

Progress Energy Regulated Service Area

Progress Ventures Georgia Electric Membership Cooperative Customers

C-02



"As we plan for tomorrow's demands, we are setting our standards higher than ever. Every day, we strive to exceed yesterday's performance in operations, customer service and overall reliability – because we believe that excellence is never where you are, but always where you're headed."

– William D. Johnson, President and Chief Operating Officer

BOARD OF DIRECTORS

Edwin B. Borden
Retired President, The Borden Manufacturing Co. (textile management services)
Goldsboro, N.C.

Elected to the board in 1985 and sits on the following committees: Corporate Governance; Organization and Compensation; Operations, Environmental, Health and Safety Issues (Chair).

James E. Bostic, Jr.
Retired Executive Vice President, Georgia-Pacific Corp. (manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals)
Atlanta, Ga.

Elected to the board in 2002 and sits on the following committees: Audit and Corporate Performance; Operations, Environmental, Health and Safety Issues.

David L. Burner
Retired Chairman and Chief Executive Officer, Goodrich Corp. (aerospace components, systems and services)
Darby, Mont.

Elected to the board in 1999 and sits on the following committees: Audit and Corporate Performance; Finance.

Charles W. Coker
Retired Chairman, Sonoco Products Co. (manufacturer of paperboard and paper and plastic packaging products)
Hartsville, S.C.

Elected to the board in 1975 and sits on the following committees: Corporate Governance; Organization and Compensation (Chair); Finance.

Richard L. Daugherty
Formerly Executive Director, NCSU Research Corp.; Vice President, IBM PC Company and Senior State Executive, IBM Corp.
Raleigh, N.C.

Elected to the board in 1992 and sits on the following committees: Audit and Corporate Performance (Chair); Corporate Governance; Operations, Environmental, Health and Safety Issues.

W. D. "Bill" Frederick, Jr.
Citrus grower and rancher, formerly mayor of Orlando and partner in the law firm of Holland & Knight
Orlando, Fla.

Elected to the board in 2000 and sits on the following committees: Audit and Corporate Performance; Operations, Environmental, Health and Safety Issues.

W. Steven Jones
Dean and Professor of Management of Kenan-Flagler Business School at the University of North Carolina at Chapel Hill
Chapel Hill, N.C.

Elected to the board in 2005 and sits on the following committees: Finance; Organization and Compensation.

William O. McCoy
Partner, Franklin Street Partners (investment management), formerly Vice Chairman of the Board, BellSouth Corp. and President and Chief Executive Officer, BellSouth Enterprises
Chapel Hill, N.C.

Elected to the board in 1996 and sits on the following committees: Organization and Compensation; Finance (Chair).

Robert B. McGehee
Chairman and Chief Executive Officer, Progress Energy, Inc.
Raleigh, N.C.

Elected to the board in 2004. Serves as Chairman, Progress Energy Carolinas and Chairman, Progress Energy Florida.

E. Marie McKee
Senior Vice President, Corning, Inc. (developer of technologies for glass, ceramics, fiber optics and photonics) and President and Chief Executive Officer, Steuben Glass
Corning, N.Y.

Elected to the board in 1999 and sits on the following committees: Organization and Compensation; Operations, Environmental, Health and Safety Issues.

John H. Mullin, III
Chairman, Ridgeway Farm, LLC (farming and timber management) and formerly a Managing Director, Dillon, Read & Co. (investment bankers)
Brookneal, Va.

Elected to the board in 1999, presiding director and sits on the following committees: Corporate Governance (Chair); Finance; Organization and Compensation.

Peter S. Rummell
Chairman and Chief Executive Officer, The St. Joe Company (real estate operating company)
Jacksonville, Fla.

Elected to the board in 2003 and sits on the following committees: Corporate Governance; Operations, Environmental, Health and Safety Issues; Organization and Compensation.

Carlos A. Saladrigas
Chairman, Premier American Bank and Retired Chief Executive Officer, ADP TotalSource
Miami, Fla.

Elected to the board in 2001 and sits on the following committees: Audit and Corporate Performance; Finance.

Theresa M. Stone
Executive Vice President and CFO, Jefferson-Pilot Financial (insurance and financial services company)
Greensboro, N.C.

Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance; Finance.

Jean Giles Wittner
President and Secretary, Wittner & Co., Inc. (real estate management and insurance brokerage and consulting)
St. Petersburg, Fla.

Elected to the board in 2000 and sits on the following committees: Audit and Corporate Performance; Operations, Environmental, Health and Safety Issues.

At Progress Energy, we consistently pursue excellence in all our endeavors. Our internal controls over financial reporting reflect that commitment and, as a result, Progress Energy achieved full compliance with the applicable internal control requirements in connection with its 2005 financial reporting processes.

RESPONSIBILITIES OF KEY BOARD COMMITTEES

Audit and Corporate Performance Committee

The work of this committee includes reviewing the annual and quarterly financial results of the company and the various periodic reports the company files with the SEC. It is responsible for retaining the company's external auditors, overseeing and monitoring the auditors' activities and pre-approving all external audit and non-audit services and fees. This committee also oversees the activities of the internal audit department and the Corporate Ethics Program.

Corporate Governance Committee

The responsibilities of this committee include making recommendations on the structure, charter, practices and policies of the board, including amendments to the articles of incorporation and bylaws. This committee ensures that processes are in place for annual CEO performance appraisal, reviews of succession planning and management development. It also recommends the process for the annual assessment of board performance and criteria for board membership. In addition, it proposes nominees to the board.

Finance Committee

This committee reviews and oversees the company's financial policies and planning and the company's pension funds. It monitors the company's financial position, reviews the company's strategic investments and financing options and recommends changes in the company's dividend policy.

Operations, Environmental, Health and Safety Issues Committee

This committee reviews the company's load forecasts and plans for generation, transmission and distribution, fuel production and transportation, customer service, energy trading, term marketing and other company operations. The committee assesses company policies, procedures and practices relative to environmental protection and safety-related issues and advises and makes recommendations to the board regarding these matters.

Organization and Compensation Committee

This committee reviews personnel policies and procedures for consistency with governmental rules and regulations and ensures that the company attracts and retains competent, talented employees. The committee reviews all executive development and management succession plans, evaluates CEO performance and makes senior executive compensation decisions.

EXECUTIVE AND SENIOR OFFICERS

Robert B. McGehee
Chairman and Chief Executive Officer

William D. Johnson
President and Chief Operating Officer

Peter M. Scott III
Chief Financial Officer
Progress Energy, Inc.
President and Chief Executive Officer
Progress Energy Service Company, LLC

Fred N. Day IV
President and Chief Executive Officer
Progress Energy Carolinas, Inc.

H. William Habermeyer, Jr.
President and Chief Executive Officer
Progress Energy Florida, Inc.

Donald K. Davis
Executive Vice President – Diversified Operations

C. S. Hinnant
Senior Vice President – Nuclear Generation
and Chief Nuclear Officer

Jeffrey J. Lyash
Senior Vice President – Energy Delivery
Progress Energy Florida, Inc.

John R. McArthur
Senior Vice President – Corporate Relations
General Counsel and Secretary

Mark F. Mulhern
President
Progress Energy Ventures, Inc.

E. Michael Williams
Senior Vice President – Power Operations

Lloyd M. Yates
Senior Vice President – Energy Delivery
Progress Energy Carolinas, Inc.

FINANCIAL REPORT

Certain matters discussed throughout this Annual Report that are not historical facts are forward looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In addition, examples of forward-looking statements discussed in this Annual Report include, but are not limited to, "Management's Discussion and Analysis" including, but not limited to, statements under the following headings: a) "Results of Operations" about trends and uncertainties; b) "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2008 and future financing plans; c) "Strategy" about our future strategy and goals; and d) "Other Matters" about our synthetic fuel facilities, the effects of new environmental regulations and the effect of electric utility industry restructuring.

Any forward-looking statement is based on information current as of the date of this report and speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and the recently enacted Energy Policy Act of 2005; the financial resources needed to comply with environmental laws; deregulation or restructuring in the electric industry that may result in increased competition and unrecovered or stranded costs; weather conditions that directly influence the demand for electricity; the ability to recover through the regulatory process costs associated with future significant weather events; recurring seasonal fluctuations in demand for electricity; fluctuations in the price of energy commodities and purchased power; economic fluctuations and the corresponding impact on our commercial and industrial customers; the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the impact on our facilities and businesses from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the anticipated future need for additional baseload generation in our regulated service territories and the accompanying regulatory and financial risks; the ability to successfully access capital markets on favorable terms; our ability to maintain our current credit ratings and the impact on our financial condition and ability to meet our cash and other financial obligations in the event our credit ratings are downgraded below investment grade; the impact that increases in leverage may have on us; the impact of derivative contracts used in the normal course of business; the investment performance of our pension and benefit plans; our ability to control costs, including pension and benefit expense, and achieve our cost-management targets for 2007; the availability and use of Internal Revenue Code Section 29/45K (Section 29/45K) tax credits by synthetic fuel producers and our continued ability to use Section 29/45K tax credits related to our coal-based solid synthetic fuel businesses; the impact that future crude oil prices may have on the value of our Section 29/45K tax credits; our ability to manage the risks involved with the operation of nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history of such plants; the ability to manage the risks associated with our energy marketing operations, including potential impairment charges caused by adverse changes in market or business conditions; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact our subsidiaries.

These and other risk factors are detailed from time to time in our filings with the United States Securities and Exchange Commission (SEC). All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the effect of each such factor on Progress Energy.

The following Management's Discussion and Analysis contains forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review the "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein. As used in this report, Progress Energy [which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis] is at times referred to as "we," "our" or "us." Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas and Progress Energy Florida, as the "Utilities." Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements.

INTRODUCTION

Our reportable business segments and their primary operations include:

- Progress Energy Carolinas (PEC) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina;
- Progress Energy Florida (PEF) – primarily engaged in the generation, transmission, distribution and sale of electricity in a portion of Florida;
- Progress Ventures – engaged in the Competitive Commercial Operations (CCO) business that includes nonregulated electric generation operations and energy marketing activities primarily in Georgia, North Carolina and Florida, as well as in natural gas production (Gas) in Texas and Louisiana; and
- Coal and Synthetic Fuels – primarily engaged in coal terminal services, fuel transportation and delivery, the production and sale of coal-based solid synthetic fuels and the operation of synthetic fuel facilities for third parties in Kentucky and West Virginia.

The Corporate and Other segment includes businesses that do not meet the requirements for separate segment reporting disclosure. These businesses are engaged in other nonregulated business areas, including telecommunications, primarily in the eastern United States, energy services operations, holding company operations and Progress Energy Service Company, LLC (PESC) operations.

In 2005, our presentation of reportable segments changed due to changes in the operations of certain businesses and the reclassification of our coal mining business as discontinued operations. These changes are consistent with the manner in which management currently reviews these operations. A summary of changes to our segment presentation is as follows: 1) report PEC's immaterial nonregulated subsidiaries that were previously included in the Corporate and Other category in the PEC segment; 2) report CCO and Gas operations together in the Progress Ventures segment; and 3) report the Synthetic Fuels operations together with the coal terminals businesses in the Coal and Synthetic Fuels segment. The Gas operations, coal terminals and synthetic fuels operations were previously reported in the Fuels segment. In addition, prior to its divestiture in 2005, Rail Services was reported as a separate segment. For comparative purposes, 2004 and 2003 segment information has been restated to align with the 2005 reporting structure.

Strategy

We are an integrated energy company, with our primary focus on the end-use and wholesale electricity markets. We operate in retail utility markets in the southeastern United States and in competitive electricity, gas and other fuels markets in the eastern United States. We are focused on the following key priorities: excelling in the daily fundamentals of our business, strengthening our financial flexibility and growth, preparing for future baseload capacity in our regulated service territories and improving the return on Progress Ventures. A summary of the significant financial objectives or issues impacting us, the Utilities and our nonregulated operations is addressed more fully in the following discussion.

We have several key financial objectives, the first of which is to achieve sustainable earnings growth in our three core energy businesses, which include PEC, PEF and Progress Ventures (CCO and Gas). In addition, we seek to continue our track record of dividend growth, as we have increased our dividend for 18 consecutive years, and 30 of the last 31. We also seek to continue our efforts to enhance balance sheet strength and flexibility by reducing holding company debt through selected asset sales, operating cash flow, cash flow benefit from deferred synthetic fuel tax credits, and limited equity issuances under our Investor Plus and employee benefit plans.

In the short term, our ability to achieve these objectives will be impacted by, among other things, cash flow available to reduce debt after funding capital expenditures and common dividends, commodity price risk, and increased environmental spending requirements. Our long-term challenges include escalating nonfuel and fuel operating costs, the need for sufficient earnings growth to sustain our track record of dividend growth, the potential for future regulation to address global climate change, the need for future baseload capacity in our regulated service territories and the scheduled expiration of Internal Revenue Code (the Code) Section 29/45K (Section 29/45K) tax credit program for our synthetic fuels business at the end of 2007.

Our ability to meet these financial objectives is largely dependent on the earnings and cash flows of the Utilities. The Utilities contributed $748 million of our segment profit and generated approximately 100 percent of our consolidated cash flow from operations in 2005. In addition, our Progress Ventures and Coal and Synthetic Fuels operations contributed $190 million of segment profit, of which $155 million represented synthetic fuel earnings. Partially offsetting the net income contribution provided by these businesses was a loss of $211 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

While our synthetic fuel operations currently provide significant net earnings that are scheduled to expire at the end of 2007 and are subject to various risks as described under the "Synthetic Fuel Tax Credits" section of OTHER MATTERS below, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred tax credits are ultimately utilized. The Code's Section 29 (Section 29) credits that have been generated through December 31, 2005, but not yet utilized are currently carried forward indefinitely as alternative minimum tax credits and will provide positive cash flow when utilized. At December 31, 2005, the amount of these deferred tax credits was $922 million. See Note 23D for additional information on our synthetic fuel operations.

Our total debt to total capitalization ratio from the Consolidated Balance Sheet is 57.7 percent at the end of 2005, which represents a slight increase over 2004, primarily due to the under-recovery of fuel costs at the Utilities during 2005 driven by rising commodity costs. We seek to improve this ratio through a reduction in total debt with proceeds from asset sales, recovery of storm costs incurred in Florida during 2004, fuel cost recovery, operating cash flow and growth in equity from retained earnings and limited ongoing equity issuances. We expect total capital expenditures to be approximately $1.8 billion in 2006 and $1.7 billion in 2007, primarily related to the Utilities' operations.

The Parent's ratings outlook was changed to "stable" from "negative" in November 2005 by Standard & Poor's (S&P). S&P cited the resolution of several regulatory issues in Florida and the expectation of increased likelihood that our financial performance will improve over the next two years in its ratings action. Moody's Investors Service, Inc. (Moody's) has had a "negative" outlook for the Parent since October 2004 and Fitch Rating's outlook for the Parent has been "stable" since February 2003. See "Credit Rating Matters" and "Guarantees" Section under FUTURE LIQUIDITY AND CAPITAL RESOURCES below for more information regarding the potential impact on our financial condition and results of operations resulting from a ratings downgrade.

REGULATED UTILITIES

The Utilities' earnings and operating cash flows are heavily influenced by weather, the economy, demand for electricity related to customer growth, actions of regulatory agencies, cost controls, the timing of recovery of fuel costs, and storm damage.

The Utilities operate in the Southeast, one of the fastest growing regions of the country, and had a net increase of approximately 60,000 customers over the past year. The Utilities' customers set several peak demand records during the summer of 2005. In recent years, lower industrial sales mainly related to weakness in the textile sector at PEC have reduced the rate of revenue growth. We do not expect any significant improvement or further degradation in industrial sales in the near term. These combined factors under normal weather conditions are expected to contribute approximately 2 percent annual retail kilowatt-hour (kWh) sales growth at PEC and approximately 2.5 percent to 3 percent annual retail kWh sales growth at PEF through at least 2008. The Utilities must continue to invest significant capital in additional energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities to support this load growth. Subject to regulatory approval, these investments are expected to increase the Utilities' rate base, upon which additional return can be realized that creates the basis for long-term earnings growth in the Utilities. We will meet this load growth through the previously planned approximately 500 MW combined cycle unit at PEF's Hines Energy Complex in 2007 and an approximately 150 MW dual-fuel combustion turbine plant at PEC in 2008. The Utilities also seek to grow their regulated wholesale business through targeted contract renewals and origination opportunities.

Meeting the anticipated growth within the Utilities' service territories will require a balanced solution. We are advocating energy conservation and efficiency and pursuing new energy technologies to help meet the expected growth in demand. We estimate that we will require new baseload generation facilities in both Florida and the Carolinas by the middle of the next decade and are evaluating all of the best available options for this generation, including advanced design nuclear and clean coal technologies. The considerations that will factor into this decision include construction costs, fuel diversity, transmission and site availability, environmental compliance, and our ability to obtain financing. See "Nuclear" Section under OTHER MATTERS for additional information.

The EPA issued two significant air quality regulations in March 2005 that affect our fossil fuel-fired generating facilities, the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). Including estimated costs for CAIR and CAMR, we currently estimate total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, a portion of which are eligible for regulatory recovery, to be in excess of $1.0 billion each at PEC and PEF, respectively, through 2018, which is the latest emission reduction deadline.

The Utilities are allowed to recover prudently incurred fuel costs through the fuel portion of our rates, which are adjusted annually in each state. We are focused on mitigating the impact of rising fuel prices since the under-recovery of fuel costs impacts our cash flows, interest and leverage, and rising fuel costs and higher rates also impact customer satisfaction. Our efforts to mitigate these high fuel costs include our diverse generation mix, staggered fuel contracts and hedging, and supplier and transportation diversity.

While the Utilities expect retail sales growth in the future, they are facing rising costs. We implemented a cost-management initiative in 2005, which we expect to permanently reduce by $75 million to $100 million the projected growth in our annual nonfuel operation and maintenance (O&M) costs by the end of 2007. See "Cost-Management Initiative" under RESULTS OF OPERATIONS for more information. The Utilities expect total capital expenditures for maintenance and growth requirements to be approximately $1.6 billion in 2006 and $1.5 billion in 2007. Operating cash flows from the Utilities are expected to be sufficient to fund their maintenance capital spending and dividends to the Parent in 2006 and 2007.

The Utilities successfully resolved major state regulatory issues in 2005, including an agreement on base rates in Florida, storm cost recovery in Florida and fuel recovery filings in South Carolina, North Carolina and Florida. The Utilities continue to monitor progress toward a more competitive environment. No retail electric restructuring legislation has been introduced in the jurisdictions in which PEC and PEF operate. As part of the Clean Smokestacks Act in North Carolina (Clean Smokestacks Act), PEC is operating under a base rate freeze in North Carolina through 2007. The PEF base rate settlement extends through 2009. See Note 7 for further discussion of the Utilities' retail rates.

NONREGULATED BUSINESSES

Our primary nonregulated businesses are Progress Ventures and Coal and Synthetic Fuels.

Cash flows and earnings of Progress Ventures are impacted largely by the ability to obtain additional term contracts or sell energy on the spot market at favorable terms, the cost of fuel and purchased power, and the volumes and prices of natural gas sales. Earnings of Coal and Synthetic Fuels are impacted largely by the volume of synthetic fuel produced and tax credits generated, and volumes and prices of coal terminal sales.

We expect an excess of peaking and mid-market generation supply in the Georgia wholesale electric energy market in which we compete for the next several years. During 2005, CCO began serving additional full-requirements wholesale power contracts at fixed prices with cooperatives in Georgia and currently serves approximately one-third of the Georgia cooperative market. CCO experienced a decrease in margins in 2005 due to expiration of above-market tolling agreements at the end of 2004 and higher fuel and purchased power costs in 2005. Continued volatility in both the commodity prices used to serve the customer load and the cooperative energy demand could further decrease the margins on these contracts and negatively impact our future results of operations. CCO has contracts for its planned production capacity, which includes callable resources from the cooperatives, of approximately 86 percent for 2006, 81 percent for 2007 and 84 percent for 2008. CCO will continue to seek opportunities to optimize our nonregulated generation portfolio.

We plan to continue to develop our natural gas production asset base as a long-term economic hedge for our nonregulated generation fuel needs. During 2006, CCO and Gas have entered into an intercompany hedge to formalize this economic relationship. While high fuel prices increase both peak and off-peak power prices and have a negative impact on our full-requirements contracts with the Georgia cooperatives, our natural gas production business benefits from these higher gas prices. We seek to continue our strategy of investing and growing our proven natural gas reserves to optimize the value of this business.

We have committed to a plan of disposal of our coal mining business and have classified these operations as discontinued operations in the accompanying financial statements. As of December 31, 2005, the carrying value of long-lived assets of the coal mining business was $73 million.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that own facilities that produce coal-based solid synthetic fuel as defined under the Internal Revenue Code. The production and sale of the synthetic fuel from these facilities qualify for tax credits under Section 29/45K if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the coal used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. The tax credits associated with future synthetic fuel production may be phased out if market prices for crude oil exceed certain prices. See additional discussion of synthetic fuel tax credits in Note 23D.

RESULTS OF OPERATIONS

In this section, earnings and the factors affecting earnings are discussed. The discussion begins with a summarized overview of our consolidated earnings, which is followed by a more detailed discussion and analysis by business segment.

Overview

For 2005 as compared to 2004 and 2004 as compared to 2003

For the year ended December 31, 2005, our net income was $697 million or $2.82 per share compared to $759 million or $3.13 per share for the same period in 2004. The decrease in net income as compared to prior year was due primarily to:

- Postretirement and severance charges related to the cost-management initiative.
- Discontinued operations and loss on disposal of Progress Rail Services Corporation (Progress Rail).
- The change in accounting estimates for certain capital costs in our distribution operations (Energy Delivery).
- Decreased nonregulated generation earnings.
- Gain on the disposition of certain Winchester Production Company, Ltd. (Winchester Production) assets in 2004.
- The write-off of unrecoverable storm costs at PEF.

Partially offsetting these items were:

- Increased synthetic fuel earnings.
- Customer growth at the Utilities.
- Favorable weather at the Utilities.
- Increased wholesale sales at the Utilities.
- Gain recorded on the sale of distribution assets at PEF.

For the year ended December 31, 2004, our net income was $759 million or $3.13 per share compared to $782 million or $3.30 per share for the same period in 2003. The decrease in net income as compared to prior year was due primarily to:

- Reduction in synthetic fuel earnings due to lower synthetic fuel sales as a result of hurricanes during 2004.
- Decreased excess generation wholesale sales, primarily at PEC.
- Increased O&M expenses at PEC.
- Recording of litigation settlement reached in the civil suit by Strategic Resource Solutions (SRS).
- Decreased nonregulated generation earnings.
- Reduction in revenues due to customer outages at PEF associated with the hurricanes.
- Increased interest charges due to the reversal of interest expense for resolved tax matters in 2003.

Partially offsetting these items were:

- Favorable weather in the Carolinas.
- Reduction in revenue sharing provisions at PEF.
- Favorable customer growth at the Utilities.
- Increased margins as a result of the allowed return on the Hines Unit 2 at PEF.
- Increased earnings for natural gas operations, which include the gain recorded on the disposition of certain Winchester Production assets.
- Increased earnings recorded for discontinued operations.
- Unrealized gains recorded on contingent value obligations (CVOs).
- Reduction in impairments recorded for an investment portfolio and long-lived assets.
- Reduction in losses recorded for changes in accounting principles.

Basic earnings per share decreased in both 2005 and 2004 due in part to the factors outlined above. Dilution related to issuances under our Investor Plus and employee benefit programs in 2005 also reduced basic earnings per share by $0.05 in 2005. Dilution related to issuances under our Investor Plus and employee benefit programs in 2004 also reduced basic earnings per share by $0.06 in 2004 as compared to 2003.

Our segments contributed the following profit or loss from continuing operations:

(in millions)	2005	Change	2004	Change	2003
PEC	$490	$32	$458	$(44)	$502
PEF	258	(75)	333	38	295
Progress Ventures	21	(60)	81	27	54
Coal and synthetic fuels	169	81	88	(102)	190
Total segment profit (loss)	938	(22)	960	(81)	1,041
Corporate and other	(211)	20	(231)	(1)	(230)
Total income from continuing operations	727	(2)	729	(82)	811
Discontinued operations, net of tax	(31)	(61)	30	35	(5)
Cumulative effect of changes in accounting principles	1	1	–	24	(24)
Net income	$697	$ (62)	$759	$(23)	$782

Cost-Management Initiative

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. The cost-management initiative is designed to permanently reduce by $75 million to $100 million our projected growth in annual O&M expenses by the end of 2007. Although we still expect nonfuel O&M expenses to grow, the cost-management initiative will lower that rate of growth and we remain on track to meet the annual target of $75 million to $100 million by the end of 2007. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005. We do not expect to incur any similar charges during 2006. The severance and postretirement charges are primarily included in O&M expense on the Consolidated Statements of Income and will be paid over time. See Note 17 for additional information on the cost-management initiative.

Progress Energy Carolinas

PEC contributed segment profits of $490 million, $458 million and $502 million in 2005, 2004 and 2003, respectively. The increase in profits for 2005 as compared to 2004 is primarily due to increased revenue from customer growth, the favorable impact of weather, increased wholesale margins primarily due to an increase in excess generation revenues and lower depreciation and amortization expense. These were partially offset by higher O&M charges primarily due to postretirement and severance charges related to the cost-management initiative and an increase in expenses charged to other, net.

The decrease in profits for 2004 as compared to 2003 was primarily due to higher O&M charges and lower wholesale revenues partially offset by the favorable impact of weather, increased revenues from customer growth and a reduction in investment losses and impairment charges compared to the prior year.

REVENUES

PEC's electric revenues and the percentage change by year and by customer class were as follows:

(in millions) Customer Class	2005	% Change	2004	% Change	2003
Residential	$1,422	7.4	$1,324	5.2	$1,259
Commercial	940	5.9	888	4.5	850
Industrial	684	3.8	659	3.6	636
Governmental	87	6.1	82	3.8	79
Total retail revenues	3,133	6.1	2,953	4.6	2,824
Wholesale	759	32.0	575	(16.3)	687
Unbilled	4	–	10	–	(6)
Miscellaneous	94	4.4	90	7.1	84
Total electric revenues	3,990	10.0	3,628	1.1	3,589
Less:					
Pass-through fuel revenues	(1,186)	–	(929)	–	(894)
Revenues excluding fuel	$2,804	3.9	$2,699	–	$2,695

PEC's electric energy sales and the percentage change by year and by customer class were as follows:

(in thousands of MWh) Customer Class	2005	% Change	2004	% Change	2003
Residential	16,664	4.1	16,003	4.7	15,283
Commercial	13,313	2.3	13,019	3.7	12,557
Industrial	12,716	(2.5)	13,036	2.3	12,749
Governmental	1,410	(1.5)	1,431	1.6	1,408
Total retail energy sales	44,103	1.4	43,489	3.6	41,997
Wholesale	15,673	18.5	13,222	(14.8)	15,518
Unbilled	(235)	–	91	–	(44)
Total MWh sales	59,541	4.8	56,802	(1.2)	57,471

PEC's revenues, less recoverable fuel costs of $1.186 billion and $929 million for 2005 and 2004, respectively, increased $105 million. The increase in revenues was due primarily to increased retail revenues of $22 million as a result of favorable weather, with cooling degree days 6 percent above prior year. Retail customer growth contributed an additional $46 million in revenues in 2005. PEC's retail customer base increased as approximately 30,000 net new customers were added in 2005. Wholesale revenues, excluding fuel revenues, increased $37 million when compared to $311 million in 2004. The increase in PEC's wholesale revenues in 2005 from 2004 is primarily the result of increased excess generation sales. Revenues for 2005 included strong sales to the mid-Atlantic United States as a result of favorable market conditions. In addition, higher contracted capacity compared to 2004 further increased wholesale revenues.

PEC's revenues, less recoverable fuel costs of $929 million and $894 million for 2004 and 2003, respectively, increased $4 million. The increase in revenues was due primarily to increased retail revenues of $35 million as a result of favorable weather, with cooling degree days 16 percent above prior year. Retail customer growth contributed an additional $55 million in revenues in 2004. PEC's retail customer base increased as approximately 26,000 net new customers were added in 2004. The increase in retail revenues was offset partially by lower wholesale revenues. Wholesale revenues, excluding recoverable fuel revenues, decreased $82 million when compared to $393 million in 2003. The decrease in PEC's wholesale revenues in 2004 from 2003 is primarily the result of reduced excess generation sales. Revenues for 2003 included strong sales to the northeastern United States as a result of favorable market conditions. In addition, lower contracted capacity compared to 2003 further reduced wholesale revenues. The remaining reduction in wholesale revenues was attributable to an inelastic power market. While the cost of fuel continued to rise, the power market prices did not respond as quickly to the fuel increases. The differential between fuel cost and market price limited opportunities to enter the market. Also, during 2003 and 2004, several contracts expired or were renegotiated at lower prices.

Fuel-adjusted industrial revenues decreased in 2005 when compared to 2004 primarily due to the reduction in textile manufacturing in the Carolinas and lower demand for both pulp and paper products. Fuel-adjusted industrial revenues increased in 2004 when compared to 2003 due to a general industrial slowdown in 2003. Decreases in the textile industry and the chemical industry were among the most significant. This declining trend leveled out in 2004 as industrial sales increased in the primary and fabricated metal, chemicals, lumber and food industries.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation, as well as energy purchased in the market to meet customer load. Fuel and purchased power expenses are recovered primarily through cost recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection or refund to customers.

Fuel and purchased power expenses were $1.390 billion for 2005, which represents a $253 million increase compared to the same period in the prior year. Fuel used in electric generation increased $200 million to $1.036 billion compared to the prior year. This increase is due to a $308 million increase in fuel used in generation due to higher fuel costs, a change in generation mix and increased volume. Higher fuel costs are being driven primarily by an increase in coal and natural gas prices. Outages at several facilities during the year resulted in increased combustion turbine generation, which has a higher average fuel cost. The increase in fuel used in generation is offset by a reduction in deferred fuel expense as a result of the under-recovery of current period fuel costs. Purchased power expenses increased $53 million to $354 million compared to prior year. The increase in purchased power is due primarily to a change in volume partially offset by a decrease in price.

Fuel and purchased power expenses were $1.137 billion for 2004, which represents a $16 million increase compared to the same period in 2003. Fuel used in electric generation increased $11 million to $836 million compared to the same period in 2003. This increase was due to a $78 million increase in fuel used in generation due to higher fuel costs and a change in generation mix. Higher fuel costs were driven primarily by an increase in coal prices. Outages at several facilities during the year resulted in increased combustion turbine generation, which has a higher average fuel cost. The increase in fuel used in generation is offset by a reduction in deferred fuel expense as a result of the under-recovery of fuel costs during 2004. Purchased power expenses increased $5 million to $301 million compared to prior year. The increase in purchased power is due primarily to an increase in price.

Operation and Maintenance

O&M expenses were $941 million for 2005, which represents a $70 million increase compared to 2004. This increase is driven primarily by current year postretirement and severance expenses related to the cost-management initiative. Postretirement and severance expenses related to the cost-management initiative increased O&M expenses by $53 million during 2005. This increase included $55 million of current year charges compared to prior year expenses, which included $2 million related to a separate initiative. In addition, O&M expenses increased $26 million related to the change in accounting estimates for certain Energy Delivery capital costs (See Note 7F), $25 million for higher emission allowance expenses, $16 million related to pension expenses and $6 million related to Hurricane Ophelia storm restoration costs in 2005. These unfavorable items were partially offset by decreased plant outage costs of $12 million compared to 2004, which included an additional nuclear plant outage, $8 million of lower health and life benefit expenses and a $6 million reduction of surplus inventory expense. In addition, results for 2004 included $19 million of costs associated with an ice storm that impacted the Carolinas service territory in the first quarter of 2004 and Hurricanes Charley and Ivan that impacted the Carolinas service territory in the third quarter of 2004.

O&M expenses were $871 million for 2004, which represented an $89 million increase compared to 2003. This increase was driven primarily by higher outage costs and storm costs in 2004 than in 2003. Outages increased O&M costs by $29 million primarily due to an increase in the number and scope of nuclear plant outages in 2004. In addition, costs associated with restoration efforts after severe storms increased O&M expense $19 million. Storm costs for 2004 included costs related to an ice storm and Hurricanes Charley and Ivan in the North Carolina service territory. PEC also incurred storm costs in 2003; however, PEC requested and the North Carolina Utilities Commission (NCUC) approved deferral of these costs. PEC did not seek to defer costs associated with any storms in its North Carolina service territory for 2004. O&M expenses also increased $9 million due to higher salary- and benefit-related expenditures. In addition, O&M charges in 2003 were favorably impacted by $16 million related to the retroactive reallocation of PESC costs.

Depreciation and Amortization

Depreciation and amortization expense was $561 million for 2005, which represents a $9 million decrease compared to 2004. This decrease is attributable primarily to the Clean Smokestacks Act amortization decrease of $27 million to $147 million in 2005 compared to amortization of $174 million in 2004. This was partially offset by higher depreciation expense of $17 million for assets placed in service.

Depreciation and amortization expense was $570 million for 2004, which represents an $8 million increase compared to 2003. This increase was attributable primarily to the impact of the Clean Smokestacks Act. Clean Smokestacks Act amortization increased $100 million to $174 million in 2004 compared to amortization of $74 million in 2003. Depreciation expense also increased $9 million for assets placed in service. These increases were partially offset by a reduction in depreciation expense related to depreciation studies filed during 2004. During 2004, PEC met the requirements of both the NCUC and the Public Service Commission of South Carolina (SCPSC) for the implementation of a depreciation study that allowed the utility to reduce the rates used to calculate depreciation expense. The annual reduction in depreciation expense is approximately $82 million compared to 2003. The reduction is due primarily to extended lives at each of PEC's nuclear units. The new rates became effective January 2004.

Taxes Other than on Income

Taxes other than on income were $178 million for 2005, which represents a $5 million increase compared to the prior year. This increase is due primarily to higher payroll taxes of $5 million and an increase in gross receipts taxes of $2 million related to an increase in revenues partially offset by a 2004 adjustment related to the prior year. These were partially offset by a $2 million reduction in property taxes due to the settlement of a South Carolina property tax issue in 2004.

Taxes other than on income were $173 million for 2004, which represents an $11 million increase compared to 2003. This increase is due primarily to an increase in gross receipts taxes of $8 million related to an increase in revenues and a 2004 adjustment related to the prior year. The remaining variance in other taxes is due to an increase in property taxes of $7 million due to higher property appraisals partially offset by a reduction in payroll taxes of $4 million.

Impairment of Investments

Impairment of investments was a loss of $1 million in 2005, zero in 2004 and a loss of $21 million in 2003. The loss in 2003 is due to impairments and an estimated loss on sale related to the Affordable Housing portfolio held by the nonutility subsidiaries of PEC (See Note 9).

Other, Net

Other, net was $14 million, $1 million and $19 million of expense for 2005, 2004 and 2003, respectively. The $13 million increase in expense for 2005 was primarily due to a $16 million indemnification liability recorded for estimated capital costs expected to be incurred in excess of the maximum billable costs to the joint owner associated with the Clean Smokestacks Act (See Note 22B) and $4 million related to an audit settlement with the Federal Energy Regulatory Commission (FERC). These were partially offset by a $7 million write-off of nontrade receivables in 2004.

Income Tax Expense

Income tax expense was $239 million, $239 million and $241 million in 2005, 2004 and 2003, respectively. Fluctuations in income taxes are primarily due to changes in pre-tax income.

Cumulative Effect of Changes in Accounting Principles

In 2003, PEC recorded cumulative effect of changes in accounting principles due to the adoption of a new accounting pronouncement. This adjustment totaled to a $23 million after-tax loss due primarily to the new Financial Accounting Standards Board (FASB) guidance related to the accounting for the purchase power contract with Broad River LLC (See Note 18A). This amount is not included in PEC's segment profit for 2003.

Progress Energy Florida

PEF contributed segment profits of $258 million, $333 million and $295 million in 2005, 2004 and 2003, respectively. The decrease in 2005 profits is primarily due to higher O&M expenses (as a result of postretirement and severance costs, the change in accounting estimates for certain Energy Delivery capital costs, the write-off of unrecovered storm costs and costs associated with outages) and lower average usage per retail customer partially offset by the favorable impact of weather, higher wholesale sales, the gain on the sale of the distribution system serving Winter Park, Fla. (Winter Park), and favorable retail customer growth.

Profits for 2004 increased due to favorable customer growth, a reduction in the provision for revenue sharing, favorable wholesale revenues, the additional return on investment on the Hines Unit 2 and reduced O&M expenses. These items were partially offset by unfavorable weather, a reduction in revenues related to the hurricanes, increased interest expense and increased depreciation expense from assets placed in service.

REVENUES

PEF's electric revenues and the percentage change by year and by customer class were as follows:

(in millions)

Customer Class	2005	% Change	2004	% Change	2003
Residential	$2,001	10.8	$1,806	6.8	$1,691
Commercial	948	11.1	853	15.3	740
Industrial	284	11.8	254	16.0	219
Governmental	242	14.7	211	16.6	181
Revenue sharing refund	(1)	–	(11)	–	(35)
Total retail revenues	3,474	11.6	3,113	11.3	2,796
Wholesale	344	28.4	268	18.1	227
Unbilled	(6)	–	7	–	(2)
Miscellaneous	143	4.4	137	4.6	131
Total electric revenues	3,955	12.2	3,525	11.8	3,152
Less:					
Fuel and other pass-through revenues	(2,385)	–	(2,007)	–	(1,692)
Revenues excluding fuel	$1,570	3.4	$1,518	4.0	$1,460

PEF's electric energy sales and the percentage change by year and by customer class were as follows:

(in thousands of MWh)

Customer Class	2005	% Change	2004	% Change	2003
Residential	19,894	2.8	19,347	(0.4)	19,429
Commercial	11,945	1.8	11,734	1.6	11,553
Industrial	4,140	1.7	4,069	1.7	4,000
Governmental	3,198	5.1	3,044	2.4	2,974
Total retail energy sales	39,177	2.6	38,194	0.6	37,956
Wholesale	5,464	7.1	5,101	18.0	4,323
Unbilled	(205)	–	358	–	233
Total MWh sales	44,436	1.8	43,653	2.7	42,512

PEF's revenues, excluding recoverable fuel and other pass-through revenues of $2.385 billion and $2.007 billion for 2005 and 2004, respectively, increased $52 million. The increase in revenues is due in part to favorable current year weather of $16 million with cooling degree days 11 percent higher than the prior year. Retail customer growth contributed an additional $21 million as approximately 30,000 net new customers (on average) were added as of December 31, 2005, compared to the prior year, and there was a significant reduction in hurricane-related customer outages compared to 2004. This growth in retail revenues was offset by lower retail revenues of $10 million in the Winter Park area due to the sale of the related distribution system in 2005 and an $8 million decline in average use per customer. Wholesale revenues net of fuel increased $18 million attributed to new contracts, including the service to Winter Park resulting from the switching of the sales to these customers from retail to wholesale. Revenues were also favorably impacted by a reduction in the provision for revenue sharing of $10 million and higher miscellaneous revenues of $6 million.

PEF's revenues, excluding recoverable fuel and other pass-through revenues of $2.007 billion and $1.692 billion for 2004 and 2003, respectively, increased $58 million. This increase was due primarily to favorable customer growth, which increased revenues $34 million. PEF had a net average increase of 37,000 retail customers compared to prior year. Revenues were also favorably impacted by a $24 million reduction in the provision for revenue sharing. Results for 2003 included an additional refund of $18 million related to the 2002 revenue sharing provision as ordered by the Florida Public Service Commission (FPSC) in July 2003. In addition, improved wholesale sales, net of fuel, increased revenues by $11 million. These increases were partially offset by the approximately $12 million reduction in revenues related to customer outages for Hurricanes Charley, Frances and Jeanne and the $10 million impact of milder weather in the current year. Included in fuel revenues is the recovery of depreciation and capital costs associated with the Hines Unit 2, which was placed into service in December 2003 and contributed $36 million in additional revenues in 2004. The recovery of the Hines Unit 2 costs through the fuel clause is in accordance with the 2002 rate stipulation (See Note 7C).

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchased for generation, as well as energy purchased in the market to meet customer load. Fuel and purchased power expenses are recovered primarily through cost recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection or refund to customers.

Fuel and purchased power expenses were $2.017 billion in 2005, which represents a $275 million increase compared to 2004. This increase is due to increases in fuel used in electric generation and purchased power expenses of $148 million and $127 million, respectively. Higher system requirements and increased fuel costs in the current year account for $342 million of the increase in fuel used in electric generation. The increase in fuel used in generation is offset by a reduction in deferred fuel expense as a result of the under-recovery of current period fuel costs. Purchased power increased primarily due to higher prices of purchases in the current year as a result of increased fuel costs.

Fuel and purchased power expenses were $1.742 billion in 2004, which represents a $306 million increase compared to 2003. This increase is due to increases in fuel used in electric generation and purchased power expenses of $305 million and $1 million, respectively. Higher system requirements and increased fuel costs in the current year account for $87 million of the increase in fuel used in electric generation. The remaining increase is due to the recovery of fuel expenses that were deferred in the prior year, partially offset by the deferral of current year under-recovered fuel expenses.

Operation and Maintenance

O&M expenses were $852 million in 2005, which represents a $222 million increase when compared to the prior year. Postretirement and severance costs associated with the cost-management initiative increased O&M costs by $102 million during 2005. In addition, PEF wrote off $17 million of unrecoverable storm costs associated with the 2004 hurricanes (See Note 7C). O&M expense also increased $37 million primarily related to the change in accounting estimates for certain Energy Delivery capital costs (See Note 7F) and increased $26 million due to higher environmental cost recovery expenses (primarily emission allowances). The environmental cost recovery expenses are pass-through expenses and have no material impact on earnings. The remaining increase in O&M expense is attributable to $9 million of expenses related to outages in the current year, an $8 million workers compensation benefit adjustment recorded in 2005, $6 million related to regional transmission organization (RTO) liability, and offsetting expense associated with prior recoveries of revenues for GridFlorida RTO startup costs that were previously deferred, and $5 million of additional bad debt expense.

O&M expenses were $630 million in 2004, which represents a $10 million decrease when compared to the prior year. This decrease is primarily related to favorable benefit-related costs of $16 million, primarily due to lower pension costs, which resulted from improved pension asset performance.

Depreciation and Amortization

Depreciation and amortization expense was $334 million for 2005, which represents an increase of $53 million when compared to the prior year, primarily due to the amortization of $50 million in storm costs that began in August 2005 (See Note 7C). Storm cost amortization is a pass-through expense and has no impact on earnings.

Depreciation and amortization expense was $281 million for 2004, which represents a decrease of $26 million when compared to the prior year, primarily due to the amortization of the Tiger Bay regulatory asset in the prior year. The Tiger Bay regulatory asset, for contract termination costs, was recovered pursuant to an agreement between PEF and the FPSC approved in 1997. The amortization of the regulatory asset was calculated using revenues collected under the fuel adjustment clause; as such, fluctuations in this expense did not have an impact on earnings. During 2003, Tiger Bay amortization was $47 million. The Tiger Bay asset was fully amortized in September 2003. The decrease in Tiger Bay amortization was partially offset by additional depreciation for assets placed in service, including depreciation for Hines Unit 2, of approximately $9 million. This depreciation expense is being recovered through the fuel cost recovery clause as allowed by the FPSC. See discussion of the return on Hines Unit 2 in the revenues analysis above.

Taxes Other than on Income

Taxes other than on income were $279 million in 2005, which represents an increase of $25 million compared to the prior year. This increase is due to increases in gross receipts and franchise taxes of $8 million each, related to an increase in revenues, a $5 million increase in payroll taxes and an increase in property taxes of $3 million. Gross receipts and franchise taxes are pass-through expenses and have no impact on earnings.

Taxes other than on income were $254 million in 2004, which represents an increase of $13 million compared to 2003. This increase is due to increases in gross receipts and franchise taxes of $8 million and $7 million, respectively, related to an increase in revenues and an increase in property taxes of $5 million due to increases in property placed in service and tax rates. These increases were partially offset by a reduction in payroll taxes of $7 million.

Interest Expense

Interest charges, net were $126 million in 2005, which represents an increase of $12 million compared to the prior year. The increase in interest expense is primarily due to increased commercial paper borrowings and increased interest expense on long-term debt.

Interest charges, net were $114 million in 2004, which represents a $23 million increase compared to 2003. The fluctuation was primarily due to interest costs in 2003 being favorably impacted by the reversal of interest expense due to the resolution of certain tax matters.

Income Tax Expense

Income tax expense was $121 million, $174 million and $147 million in 2005, 2004 and 2003, respectively. Fluctuations in income taxes are primarily due to changes in pre-tax income.

Progress Ventures

The Progress Ventures segment includes the operations of CCO and Gas. These operations are involved in the generation and sale of electricity to the wholesale market and natural gas drilling and production.

The following summarizes segment profits of Progress Ventures:

(in millions)	2005	2004	2003
Competitive Commercial Operations	$(35)	$(4)	$20
Natural gas operations	56	85	34
Segment profits	$21	$81	$54

COMPETITIVE COMMERCIAL OPERATIONS

CCO generates and sells electricity to the wholesale market from nonregulated plants. These operations also include marketing activities. The following summarizes the annual revenues, gross margin and segment profits from the CCO plants:

(in millions)	2005	2004	2003
Total revenues	$694	$240	$170
Gross margin			
In millions of $	$79	$158	$141
As a % of revenues	11%	66%	83%
Profits (losses)	$(35)	$(4)	$20

CCO's operations generated losses of $35 million in 2005 compared to losses of $4 million in 2004. The decrease in earnings compared to prior year is due primarily to a reduction in gross margin of $79 million pre-tax ($47 million after-tax) partially offset by favorable amortization expense and interest expense. Contract margins are unfavorable compared to prior year due to the expiration of certain above-market tolling agreements and decreased earnings from new and existing full-requirements contracts due to higher fuel and purchased power costs partially offset by net realized and unrealized mark-to-market gains. Depreciation and amortization expenses decreased $6 million pre-tax ($4 million after-tax) as a result of the expiration of certain acquired contracts that were subject to amortization. Interest expense decreased $15 million pre-tax ($9 million after-tax) due to the termination of the Progress Genco Ventures LLC (Genco) financing arrangement in December 2004.

CCO's operations generated losses of $4 million in 2004 compared to profits of $20 million in 2003. Results for 2004 were favorably impacted by increased gross margin, which was more than offset by higher fixed costs and costs associated with the extinguishment of debt. Revenues increased for 2004 due to increased revenues from marketing and tolling contracts offset by a termination payment received on a marketing contract in 2003. Expenses for the cost of fuel and purchased power to supply marketing contracts partially offset the increased revenues netting to an increase in gross margin for 2004 as compared to 2003. Fixed costs increased $16 million pre-tax from additional depreciation and amortization on plants placed into service in 2003 and from an increase in interest expense of $13 million pre-tax due primarily to interest no longer being capitalized due to the completion of construction in the prior year. In addition, plant operating expenses increased $12 million pre-tax primarily due to higher gas transportation service charges, which increased over prior year due to a full period of expenses being reflected in current year results. CCO results for 2004 also include losses of $15 million pre-tax associated with the extinguishment of a debt obligation. CCO terminated the Genco financing arrangement in December 2004. The $15 million pre-tax loss is comprised of a $9 million write-off of remaining unamortized debt issuance costs and a $6 million realized loss on exiting the related interest rate hedge. Results for 2003 were negatively impacted by the retroactive reallocation of PESC costs of $3 million ($2 million after-tax).

We have contracts for CCO's planned production capacity, which includes callable resources from the cooperatives, of approximately 86 percent for 2006, approximately 81 percent for 2007 and approximately 84 percent for 2008. We continue to seek opportunities to optimize our nonregulated generation portfolio.

In accordance with accounting standards for goodwill and long-lived assets, we have continued to monitor the carrying value of our goodwill and long-lived assets of our CCO operations. Our analyses have continued to support the carrying value of the $64 million of goodwill and the $1.4 billion of long-lived and intangible assets at December 31, 2005. However, as part of our evaluation of certain business opportunities in the first quarter of 2006, we performed an interim impairment test for the $64 million of goodwill, which indicated the fair value of our Georgia Region reporting unit was less than its carrying value. As required by Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), we are currently performing the second step of the impairment test, which compares the implied fair value of the goodwill with the recorded goodwill. While the results of the second step of the impairment test are currently unknown, the effects could range from no change to the recorded goodwill value to a potential write-off of $64 million. Future adverse changes in market conditions or changes in business conditions, including the manner in which the long-lived assets are deployed, could require future impairment evaluations of these or other assets, which could result in an impairment charge.

NATURAL GAS OPERATIONS

Gas operations generated profits of $56 million, $85 million and $34 million for the years ended December 31, 2005, 2004 and 2003, respectively. Natural gas profits decreased $29 million in 2005 compared to 2004. This decrease is attributable primarily to the gain recognized on the sale of gas assets during the prior year. In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production (North Texas gas operations). Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting the pre-tax gain of $56 million ($31 million net of taxes) was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. In addition, lower sales and general and administrative expenses and interest expenses partially offset by lower revenues reduced the overall earnings decline from 2004 to 2005. Revenues were lower due to the sale of the North Texas gas operations; however, the Texas/Louisiana gas operations were able to offset a majority of the lost revenue due to higher natural gas prices and increased production.

During 2005, we increased our proven gas reserves from 247 billion cubic feet (Bcf) equivalent at December 31, 2004, to 325 Bcf at December 31, 2005, as estimated by our independent engineering firm. The increase in reserves in 2005 is primarily from additional drilling and limited acquisitions of additional gas reserves.

Natural gas profits increased $51 million in 2004 compared to 2003. This increase is attributable primarily to the gain recognized on the sale of the North Texas gas operations assets during the year. In addition, an increase in production, coupled with higher gas prices in 2004, contributed to the increased earnings in 2004 as compared to 2003. Production levels increased resulting from the acquisition of North Texas Gas in late February 2003 and increased drilling in 2004. Volumes and prices increased 21 percent and 16 percent, respectively, for 2004 compared to 2003.

The following table summarizes the production in Bcf and revenues of the natural gas operations by location:

	2005	2004	2003
Production in Bcf equivalent			
Texas/Louisiana gas operations	24	20	13
North Texas gas operations	–	10	7
Mesa	–	–	5
Total production	24	30	25
Revenues in millions			
Texas/Louisiana gas operations	$159	$110	$65
North Texas gas operations	–	52	38
Mesa	–	–	13
Total revenues	$159	$162	$116
Gross margin			
In millions of $	$124	$126	$91
As a % of revenues	78%	78%	78%
Profits	$56	$85	$54

Coal and Synthetic Fuels

The operations of Coal and Synthetic Fuels' segment include synthetic fuels production and coal terminal operations. The following summarizes Coal and Synthetic Fuels' segment profits:

(in millions)	2005	2004	2003
Synthetic fuel operations	$155	$91	$205
Coal terminals and marketing	41	30	7
Corporate overhead and other operations	(27)	(33)	(22)
Segment profits	$169	$88	$190

SYNTHETIC FUEL OPERATIONS

The production and sale of synthetic fuel generate operating losses, but qualify for tax credits under Section 29/45K, which more than offset the effect of such losses (See Note 23D).

Results from the synthetic fuel operations are summarized in the following table:

(in millions)	2005	2004	2003
Tons sold	10.1	8.3	12.4
After-tax losses (excluding tax credits)	$(127)	$(124)	$(141)
Tax credits	282	215	346
Net profit	$155	$91	$205

Through December 31, 2005, our synthetic fuel production levels and the amount of tax credits we could claim each year were a function of our projected consolidated regular federal income tax liability. See Note 23D for information on the redesignation of the Section 29 tax credit as a Section 45K general business credit (Section 45K) effective January 1, 2006. Synthetic fuel operations' net profits increased in 2005 as compared to 2004 due primarily to an increase in synthetic fuel production and an additional $23 million gain recognized on the monetization of the Colona facility compared to 2004 (See Note 3F) partially offset by an increase in operating expenses. In addition, earnings in 2005 include $10 million favorable tax credit true-up related to 2004. Our total synthetic fuel production of approximately 10 million tons in 2005 is greater than 2004 production levels of approximately 8 million tons as a result of hurricane costs in 2004, which reduced our projected 2004 regular tax liability and our corresponding ability to record tax credits from its synthetic fuel production.

Synthetic fuel operations' net profits decreased in 2004 as compared to 2003 due primarily to a decrease in synthetic fuel production and an increase in operating expenses in 2004. Our total synthetic fuel production of approximately 8 million tons in 2004 is lower than 2003 production levels of approximately 12 million tons due to the impact of hurricane costs as described above. In addition, earnings in 2003 include a $13 million favorable tax credit true-up related to 2002.

Our future synthetic fuel production levels for 2006 and 2007 remain uncertain due to the recent volatility of oil prices. See Note 23D for additional information on the potential impact of crude oil prices on our synthetic fuel production. In addition, proposed federal legislation would establish both the 2006 Annual Average Price and 2006 Phase-out Price based on the previous calendar year. If the proposed legislation becomes law, we do not anticipate that we will reach the minimum phase-out levels in 2006. However, we cannot predict what impact, if any, this proposed legislation would have on the value of the tax credits in 2007. We cannot provide any certainty that the proposed federal legislation will be enacted into law. We are currently producing synthetic fuel at a reduced level pending resolution of the proposed legislation. If the legislation is not enacted into law as currently written or oil prices remain at levels high enough to cause a phase-out of 2006 Section 29/45K tax credits or eliminate the tax credits completely, there could be a negative impact on our results of operations and financial condition associated with operating losses incurred from the amount of synthetic fuel produced during 2006.

COAL TERMINALS AND MARKETING

Coal terminals and marketing (Coal) operations blend and transload coal as part of the trucking, rail and barge network for coal delivery. This business also has an operating fee agreement with our synthetic fuel operations for procuring and processing of coal and the transloading and marketing of synthetic fuels. Coal operations contributed earnings of $41 million, $30 million and $7 million in 2005, 2004 and 2003, respectively. As a result of the relationship with the synthetic fuels operations, fluctuations in Coal's annual earnings are primarily related to production volumes at our synthetic fuel plants. The increase in earnings for 2005 compared to 2004 is primarily due to additional revenues at the coal terminals related to increased prices and volumes and additional intersegment fees for both the coal terminals and marketing operations due to increased synthetic fuel production. These were partially offset by an increase in the cost of coal purchased by the coal terminals operations due to increased prices and larger volumes and lower third-party sales by the marketing operations. The $23 million increase in segment earnings for 2004 compared to 2003 was primarily due to increased volumes and prices.

CORPORATE OVERHEAD AND OTHER OPERATIONS

Corporate overhead and other operations incurred losses of $27 million, $33 million and $22 million for the years ended December 31, 2005, 2004 and 2003, respectively. The decrease in losses for 2005 is primarily due to lower interest expenses due to paying down debt with the proceeds from the sale of Progress Rail. The increase in 2004 losses compared to 2003 was due to the impact of $10 million of higher corporate costs in 2004. Corporate costs in 2003 included $4 million of favorability related to the reduction of an environmental reserve (See Note 22A). The remaining unfavorability in corporate costs is attributable to increased interest expense related to unresolved tax matters and higher professional fees.

Corporate and Other

The Corporate and Other segment consists of the operations of the Parent, PESC and other consolidating and nonoperating entities. Corporate and Other also includes other nonregulated business areas, including the operations of SRS and the telecommunications operations.

OTHER NONREGULATED BUSINESS AREAS

Other nonregulated business areas include the operations of SRS and the telecommunications operations. SRS was engaged in providing energy services to industrial, commercial and institutional customers to help manage energy costs primarily in the southeastern United States. During 2004, SRS sold its subsidiary, Progress Energy Solutions (PES). With the disposition of PES, we exited this business area. Telecommunication operations provide broadband capacity services, dark fiber and wireless services in Florida and the eastern United States. In December 2003, our wholly owned telecommunication subsidiaries, Progress Telecommunications Corporation (PTC) and Caronet, Inc. (Caronet), and EPIK Communications, Inc. (EPIK), a wholly owned subsidiary of Odyssey Telecorp, Inc. (Odyssey), contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC (PT LLC), a subsidiary of PTC. The accounts of PT LLC have been included in the Consolidated Financial Statements since the transaction date. See additional discussion on the telecommunication business combination in Note 4B.

Other nonregulated business areas contributed segment earnings of $4 million compared to losses of $32 million for the years ended December 31, 2005, and 2004, respectively. SRS recorded earnings of $2 million for 2005 compared to a net loss of $27 million for 2004. The net earnings for SRS were due to the recording of insurance proceeds associated with the San Francisco United School District (the District) matter, described below, partially offset by the recording of a settlement related to a military contract. The prior year loss was due primarily to the recording of the litigation settlement reached with the District related to civil proceedings. In June 2004, SRS reached a settlement with the District that settled all outstanding claims for approximately $43 million pre-tax ($29 million after-tax). The reduction in earnings due to the settlement was offset partially by a gain recognized on the sale of PES. Telecommunication operations recorded earnings of $2 million in 2005 compared to a net loss of $5 million in 2004. The change from a net loss in 2004 to net profit in 2005 is due to increased revenues from new customers, the settlement of contract disputes and a reduction in professional fees related to the merger of PTC with EPIK.

Other nonregulated business areas contributed segment losses of $32 million compared to losses of $4 million for the years ended December 31, 2004, and 2003, respectively. SRS recorded a net loss of $27 million for 2004 compared to a net loss of $6 million for 2003. The increased loss compared to the prior year is due primarily to the recording of the litigation settlement reached with the District related to civil proceedings. Telecommunication operations recorded a net loss of $5 million in 2004 compared to a net profit of $2 million in 2003. The increase in losses compared to 2003 was due to an increase in fixed costs, mainly depreciation expense, and professional fees related to the merger of PTC with EPIK.

On January 25, 2006, we signed a definitive agreement to sell PT LLC to Level 3 Communications, Inc. (Level 3) for a purchase price of approximately $137 million. We expect to use net cash proceeds of approximately $70 million from the sale of our interest in PT LLC to reduce debt (See Note 25).

CORPORATE SERVICES

Corporate Services (Corporate) includes the operations of the Parent, PESC and other consolidating and nonoperating entities. Corporate Services income (expense) is summarized below:

(in millions)	2005	Change	2004	Change	2003
Other interest expense	$(283)	$(8)	$(275)	$10	$(285)
Contingent value obligations	6	(3)	9	18	(9)
Tax reallocation	(38)	(1)	(37)	1	(38)
Other income taxes	105	1	104	(20)	124
Other income (expense)	(5)	(5)	–	18	(18)
Corporate services expense	$(215)	$(16)	$(199)	$27	$(226)

The increase in other interest expense for 2005 compared to 2004 is primarily due to a decrease in interest rate swap activity that benefited from lower variable rates during 2004. The other interest expense decrease for 2004 compared to 2003 is partially due to the repayment of a $500 million unsecured note by the Parent on March 1, 2004, which reduced interest expense by $27 million pre-tax for 2004. This reduction was offset by interest no longer being capitalized due to the completion of construction in the CCO segment in 2003. Approximately $10 million ($6 million after-tax) was capitalized in 2003. No interest expense was capitalized during 2004.

Progress Energy issued 98.6 million CVOs in connection with the acquisition of FPC in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuel facilities owned by Progress Energy. The payments, if any, are based on the net after-tax cash flows the facilities generate. At December 31, 2005, 2004 and 2003, the CVOs had a fair market value of approximately $7 million, $13 million and $23 million, respectively. Progress Energy recorded an unrealized gain of $6 million and $9 million for 2005 and 2004, respectively, and an unrealized loss of $9 million for 2003 to record the changes in fair value of CVOs, which had average unit prices of $0.07, $0.14 and $0.23 at December 31, 2005, 2004 and 2003, respectively.

Progress Energy and its affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to subsidiaries in accordance with the Intercompany Income Tax Allocation Agreement (Tax Agreement). The Tax Agreement provided an allocation that recognizes positive and negative corporate taxable income. The Tax Agreement provides for an equitable method of apportioning the carry over of uncompensated tax benefits. Since 2002, Parent tax benefits not related to acquisition interest expense were allocated to profitable subsidiaries, in accordance with a Public Utility Holding Company Act of 1935, as amended (PUHCA) order. Due to the repeal of PUHCA, we will no longer allocate these tax benefits to subsidiaries beginning in 2006.

Other income taxes benefit decreased for 2004 compared to 2003 due primarily to increased taxes recorded at the Parent of $20 million. Income taxes increased an additional $9 million at the Parent as a result of a reserve recorded related to identified state tax deficiencies. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Discontinued Operations

On March 24, 2005, we completed the sale of Progress Rail to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Gross cash proceeds from the sale were $429 million, consisting of $405 million base proceeds plus a working capital adjustment. Proceeds from the sale were used to reduce debt. The accompanying consolidated financial statements have been restated for all periods presented for the discontinued operations of Progress Rail (See Note 3B).

Progress Rail discontinued operations resulted in losses of $20 million for 2005 compared to profits of $29 million for 2004. Earnings for 2005 include an estimated after-tax loss on the sale of $25 million. Results for 2004 included 12 months of earnings activity compared to only three months in 2005. Rail discontinued operations contributed $29 million of profits in 2004 compared to $14 million in 2003. The 2004 profits were impacted by a strong scrap metal market in 2004. This resulted in increased volumes and higher prices in recycling operations, which increased annualized tonnage for recycling operations 35 percent and significantly increased revenues compared to 2003. This was partially offset by increased cost of goods sold due to the increased volume in the recycling operations.

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels Corporation (Progress Fuels) engaged in the coal mining business. The coal mining operations are expected to be sold by the end of 2006. As a result, we have classified the coal mining operations as discontinued operations in the accompanying consolidated financial statements for all periods presented (See Note 3A). The coal mining discontinued operations resulted in losses of $11 million, $5 million and $11 million for 2005, 2004 and 2003, respectively. The increased losses in 2005 as compared to 2004 are primarily due to higher coal mining costs resulting from increased production volumes, less productive mining conditions and mining startup costs. The reduction of losses in 2004 compared to 2003 is primarily due to higher volumes and margins for coal production. In addition, 2003 results included the recording of an impairment of certain assets at the Kentucky May coal mine totaling $11 million after-tax.

North Carolina Natural Gas Corporation (NCNG) discontinued operations contributed $6 million of net income for 2004. The sale of NCNG to Piedmont Natural Gas Company closed in 2003; however, during 2004, we recorded an additional gain of $6 million after-tax related to deferred taxes on the loss from the sale. In 2003, NCNG discontinued operations incurred an $8 million loss primarily due to the after-tax loss on the sale of $12 million (See Note 3H).

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We prepared our Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States. In doing so, we made certain estimates that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on our financial results and are subject to the greatest amount of subjectivity. We have discussed the development and selection of these critical accounting policies with the Audit Committee of our board of directors.

Utility Regulation

As discussed in Note 7, our regulated utilities segments are subject to regulation that sets the prices (rates) we are permitted to charge customers based on the costs that regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by a nonregulated company. This ratemaking process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the different ratemaking processes in each state in which we operate, a significant amount of regulatory assets has been recorded. We continually review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. Additionally, the state regulatory agencies often provide flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets. See Note 7 for additional information related to the impact of utility regulation on our operations.

Asset Impairments

As discussed in Note 9, we evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever indicators exist. Examples of these indicators include current period losses combined with a history of losses, a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an indicator exists, the asset group held and used is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. Performing an impairment test on long-lived assets involves management's judgment in areas such as identifying circumstances indicating an impairment may exist, identifying and grouping affected assets at the appropriate level, and developing the undiscounted cash flows associated with the asset group. Estimates of future cash flows contemplate factors such as expected use of the assets, future production and sales levels and expected fluctuations of prices of commodities sold and consumed. Therefore, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

The carrying value of our total utility plant, net is $14.442 billion at December 31, 2005. The carrying value of our total diversified business property, net and total intangible assets, net is $1.880 billion and $302 million, respectively, at December 31, 2005. Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred.

Due to the significant uncertainty surrounding our synthetic fuel production in 2006 and beyond based on the current level of oil prices, we evaluated our synthetic fuel and other related operating long-lived assets for impairment during the third and fourth quarters of 2005. We determined that no impairment of these assets was required. However, as discussed in the Synthetic Fuels Tax Credit section below, certain increases in oil prices could cause a reduction in or complete phase-out of the synthetic fuel tax credits. If this were to occur, it could no longer be economically beneficial to continue producing synthetic fuel, which could result in a future impairment charge for these assets. The synthetic fuel and other related assets have total carrying values of approximately $111 million as of December 31, 2005. The majority of these assets will be fully depreciated by the end of 2007, the scheduled end of the Section 29 tax credit program. The outcome of this matter cannot be determined.

Due to the reduction in coal production at the Kentucky May coal mine, we evaluated its long-lived assets in 2003 and recorded an impairment of $17 million pre-tax ($11 million after-tax). Fair value was determined based on discounted cash flows. The fair value of these assets was determined considering various factors, including a valuation study heavily weighted on a discounted cash flow methodology and using market approaches as supporting information.

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. In 2005 and 2003, we recorded impairments of $1 million and $18 million pre-tax, respectively, related to PEC's AHI portfolio. The AHI portfolio was deemed to be impaired based on various factors, including continued operating losses of the AHI portfolio and management performance issues arising at certain properties within the AHI portfolio. PEC also recorded an impairment of $3 million for a cost investment in 2003. The carrying value of the AHI portfolio is $3 million and $4 million as of December 31, 2005 and 2004, respectively.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) does not exceed total capitalized costs, we are required to write-down capitalized costs to the ceiling. We perform this ceiling test calculation every quarter. No write-downs were required in 2005, 2004 or 2003. At December 31, 2005, our ceiling was calculated at approximately $1.1 billion and our net capitalized costs were approximately $400 million.

Goodwill

As discussed in Note 8, we account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. For our utility segments, the goodwill impairment tests are performed at the utility operating segment level. We performed the annual goodwill impairment test for both the PEC and PEF segments in the second quarters of 2005 and 2004, each of which indicated no impairment. If the fair values for the utility segments were lower by approximately 10 percent, there still would be no impact on the reported value of their goodwill.

For our Progress Ventures segment, the goodwill impairment tests are performed at our Georgia Region reporting unit level, which is one level below the Progress Ventures segment. We performed the annual goodwill impairment test for our Georgia Region reporting unit in the first quarters of 2005 and 2004, each of which indicated no impairment. In response to changing gas and electricity prices that have a significant impact on the future cash flows of our Georgia Region operations, we also performed an interim goodwill impairment test for the Progress Ventures goodwill in the third and fourth quarters of 2005, each of which indicated no impairment. If the fair value of our Georgia Region was lower by 10 percent, then the fair value would have been less than our carrying value and we would have been required to perform additional procedures under SFAS No. 142 to determine if the goodwill was impaired.

We calculated the fair value of our segments and reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow methodology and published industry valuations and market data as supporting information. These calculations are dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates, and assumptions about the timing of when unregulated energy supply and demand would reach market equilibrium. These underlying assumptions and estimates are made as of a point in time; subsequent changes, particularly changes in the discount rates, growth rates or the timing of market equilibrium, could result in a future impairment charge to goodwill.

The carrying amounts of goodwill at December 31, 2005 and 2004, for reportable segments PEC, PEF and Progress Ventures, were $1.922 billion, $1.733 billion and $64 million, respectively.

Synthetic Fuels Tax Credits

As discussed in Note 23D, our Coal and Synthetic Fuels business unit owns facilities that produce coal-based solid synthetic fuel as defined under the Internal Revenue Code. The production and sale of the synthetic fuels from these facilities qualifies for tax credits under Section 29/45K if certain requirements are satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the synthetic fuels were produced from a facility placed in service before July 1, 1998. For 2005 and prior years, the amount of Section 29 credits that we were allowed to generate in any calendar year was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized through December 31, 2005, are carried forward indefinitely as deferred alternative minimum tax credits on the Consolidated Balance Sheets. For 2006 and forward, the Section 29 tax credits have been redesignated as a Section 45K general business credit, which removes the regular federal income tax liability limit on synthetic fuel production and subjects the credits to a 20-year carry forward period. This provision would allow us to produce synthetic fuel to a higher level than we have historically produced should we choose to do so. The current Section 29/45K tax credit program expires at the end of 2007.

In addition, Section 29 provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold value (the Threshold Price), the amount of the Section 29 tax credits are reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. We do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits related to synthetic fuel production in 2005. For 2006 synthetic fuel production, the 2006 Annual Average Price is not known until after the end of the year; we will record the 2006 tax credits based on our estimates of what we believe the Annual Average Price will be for 2006. These estimates are based on oil prices in the futures market. Any portion of the tax credits that would be phased out based on the projected 2006 Annual Average Price exceeding the Threshold Price are not recorded. We estimate that the 2006 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $66 per barrel, based on estimated inflation adjustments for 2005 and 2006. The monthly Domestic Crude Oil First Purchases Price published by the Energy Information Agency (EIA) has recently averaged approximately $5 lower than the corresponding monthly New York Mercantile Exchange (NYMEX) settlement price for light sweet crude oil. As of January 31, 2006, the average NYMEX futures price for light sweet crude oil for calendar year 2006 was $69 per barrel. Based upon the estimated 2006 Threshold Price and Phase-out Price, if oil prices for 2006 remained at the January 31, 2006 average futures price level of $69 per barrel for the entire year in 2006, we currently estimate that the synthetic fuel tax credit amount for 2006 would be reduced by approximately 75 percent to 85 percent. See further discussion in "OTHER MATTERS" below and Note 23D.

Pension Costs

As discussed in Note 16A, Progress Energy maintains qualified noncontributory defined benefit retirement (pension) plans. Our reported costs are dependent on numerous factors resulting from actual plan experience and assumptions of future experience. For example, such costs are impacted by employee demographics, changes made to plan provisions, actual plan asset returns and key actuarial assumptions, such as expected long-term rates of return on plan assets and discount rates used in determining benefit obligations and annual costs.

Due to a slight decline in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate used to present value future benefit payments, we lowered the discount rate to approximately 5.7% at December 31, 2005, which will increase the 2006 benefit costs recognized, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study by our actuary, which matches our projected benefit payments to a high-quality corporate yield curve. Plan assets performed well in 2005, with returns of approximately 11%. That positive asset performance will result in decreased pension costs in 2006, all other factors remaining constant. Due to our early retirement program, larger-than-normal lump-sum pension benefit payments were made from pension plan assets in 2005, which will increase 2006 benefit costs recognized, all other factors remaining constant. Evaluations of the effects of these and other factors have not been completed, but we estimate that the total cost recognized for pensions in 2006 will be $33 million to $43 million, compared with $38 million recognized in 2005, excluding the effect of special termination benefits that were recorded in 2005 due to our early retirement program. A $123 million charge was recorded in 2005 for those special termination benefits.

We have pension plan assets with a fair value of approximately $1.8 billion at December 31, 2005. Our expected rate of return on pension plan assets is 9.0%. We review this rate on a regular basis. Under SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2005, we elected to lower our expected rate of return from 9.25% to 9.0%. The 9.0% rate of return represents the lower end of our future expected return range given our asset allocation policy. A 0.25 percent change in the expected rate of return for 2005 would have changed 2005 pension costs by approximately $4 million.

Another factor affecting our pension costs, and sensitivity of the costs to plan asset performance, is its selection of a method to determine the market-related value of assets, i.e., the asset value to which the 9.0% expected long-term rate of return is applied. SFAS No. 87 specifies that entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. We have historically used a five-year averaging method. When we acquired Florida Progress Corporation (Florida Progress) in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. Changes in plan asset performance are reflected in pension costs sooner under the fair value method than the five-year averaging method, and, therefore, pension costs tend to be more volatile using the fair value method. Approximately 50 percent of our pension plan assets are subject to each of the two methods.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Progress Energy, Inc. is a registered holding company and, as such, has no operations of its own. Our primary cash needs at the Parent level are our common stock dividend and interest and principal payments on our $4.3 billion of senior unsecured debt. Our ability to meet these needs is dependent on the earnings and cash flows of the Utilities and our nonregulated subsidiaries, and the ability of our subsidiaries to pay dividends or repay funds to us.

Our other significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations and expenditures for our diversified businesses, primarily those of the Progress Ventures segment.

We rely upon our operating cash flow, primarily generated by the Utilities, commercial paper and bank facilities, and our ability to access long-term debt and equity capital markets for sources of liquidity.

The majority of our operating costs are related to the Utilities. A significant portion of the Utilities' costs, including the cost of fuel and purchased power, is recovered from customers in accordance with rate plans. We are allowed to recover certain fuel costs incurred by PEC and PEF through their respective fuel cost recovery clauses. Fuel price volatility can lead to over- or under-recovery of fuel costs, as changes in fuel prices are not immediately reflected in fuel surcharges due to regulatory lag in setting the surcharges. As a result, fuel price volatility can be both a source of and a use of liquidity resources, depending on what phase of the cycle of price volatility we are experiencing. Changes in the Utilities' fuel and purchased power costs may affect the timing of cash flows but not net income.

Prior to February 8, 2006, we were a registered holding company under PUHCA and therefore we obtained approval from the SEC for the issuance and sale of securities as well as the establishment of intercompany extensions of credit (utility and nonutility money pools). PEC and PEF participate in the utility money pool, which allows the two utilities to lend to and borrow from each other. A nonutility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and nonutility money pools but cannot borrow funds. The Energy Policy Act of 2005 repealed PUHCA effective February 8, 2006, and transferred to the FERC certain new responsibilities with respect to the regulation of utility holding companies. Pursuant to a recent rule adopted by the FERC, utility holding companies are allowed to continue to engage in financings authorized by the SEC provided the authorization orders have been filed with the FERC and the holding company continues to comply with such orders, terms and conditions. We have filed all such SEC orders with the FERC; therefore, we are permitted to continue all such financing transactions. The FERC has determined that it will not extend its cash management rules to holding companies.

Cash from operations, asset sales and limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans are expected to fund capital expenditures and common stock dividends for 2006. Any excess cash proceeds would be used to reduce debt. To the extent necessary, short-term and long-term debt may also be used as a source of liquidity.

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. Risk factors associated with credit facilities and credit ratings are discussed below.

The following discussion of our liquidity and capital resources is on a consolidated basis.

Historical for 2005 as Compared to 2004 and 2004 as Compared to 2003

CASH FLOWS FROM OPERATIONS

Cash from operations is the primary source used to meet operating requirements and capital expenditures. Net cash provided by operating activities from continuing operations for the three years ending December 31, 2005, 2004 and 2003, was $1.474 billion, $1.565 billion and $1.588 billion, respectively.

Cash from operating activities for 2005 decreased when compared with 2004. The $91 million decrease in operating cash flow was primarily due to a $298 million increase in the under-recovery of fuel costs at the Utilities driven by rising fuel costs and increased working capital needs, partially offset by a $193 million reduction in storm cost spending at PEF in 2005 compared to 2004. Cash from operating activities for 2005 also includes a $141 million prepayment received from a wholesale customer. In November 2005, PEC entered into a contract with the Public Works Commission of the City of Fayetteville, North Carolina (PWC) in which the PWC prepaid $141 million in exchange for future capacity and energy power sales. The prepayment is expected to cover approximately two years of electricity service and includes a prepayment discount of approximately $16 million. In 2005, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. PEF also received approval from the FPSC authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" below and Note 7 for additional information.

The increase in working capital needs for 2005 compared to 2004 was mainly driven by a $183 million increase in the change in receivables and a $53 million increase in inventory purchases, primarily coal at PEC. These impacts were partially offset by a $166 million increase in the change in accounts payable and the current portion of the prepayment received from the PWC as discussed above. The increase in the change in receivables is primarily due to increased sales at the Utilities driven by weather, rising fuel costs and timing of receipts, and increased sales at our nonregulated subsidiaries, mainly driven by rising gas prices and changes in the production level of our synthetic fuel plants over the prior year. The change in accounts payable is primarily due to higher fuel prices and increased quantities of fuel purchases at our nonregulated subsidiaries.

Cash from operating activities decreased $23 million for 2004 when compared with 2003 as the net result of the impact of hurricane costs in 2004, partially offset by the impact of an under-recovery of fuel costs in 2003. In 2004, the FPSC agreed with PEF to defer under-recovered fuel costs over a two-year period.

INVESTING ACTIVITIES

Net cash used in investing activities for the three years ending December 31, 2005, 2004 and 2003, was $1.117 billion, $0.811 billion and $1.416 billion, respectively.

Utility property additions for our regulated electric operations were $1.080 billion or approximately 76 percent of consolidated capital expenditures in 2005 and $0.998 billion or approximately 78 percent of consolidated capital expenditures in 2004. Capital expenditures for our regulated electric operations are primarily for normal construction activity and ongoing capital expenditures related to environmental compliance programs. Capital expenditures for our nonregulated operations are primarily for natural gas development activities and normal construction activity.

Excluding proceeds from sales of subsidiaries and other investments, cash used in investing activities increased approximately $408 million in 2005 when compared with 2004. The increase is due primarily to a $254 million decrease in net proceeds from available-for-sale securities and other long-term investments and $144 million in additional capital expenditures for property and nuclear fuel additions. Available-for-sale securities and other long-term investments include marketable debt securities and investments held in nuclear decommissioning and benefit investment trusts. The increase in diversified business property additions is primarily due to the acquisition of additional natural gas wells (See Note 4A).

During 2005, sales of subsidiaries and other investments primarily included $405 million in base proceeds from the sale of Progress Rail in March 2005 and $42 million in proceeds from the sale of Winter Park distribution assets in June 2005 (See Notes 3B and 3D).

Excluding proceeds from sales of subsidiaries and other investments, cash used in investing activities decreased approximately $811 million in 2004 when compared with 2003. The decrease is due primarily to the acquisition of a nonregulated generation contract and acquisition of gas assets in 2003 and net proceeds from available-for-sale securities and other long-term investments in 2004, compared to net purchases in 2003.

During 2004, sales of subsidiaries and other investments primarily included proceeds from the sale of Railcar Ltd. assets of approximately $75 million and proceeds of approximately $251 million related to the sale of natural gas assets in the Forth Worth basin of Texas. We used the proceeds from these sales to reduce indebtedness, including $241 million to pay off the Genco bank facility.

During 2003, we realized approximately $450 million of net cash proceeds from the sale of NCNG and ENCNG. We also received net proceeds of approximately $97 million in October 2003 for the sale of our Mesa gas properties in Colorado (See Note 3G). The proceeds from these sales were used to reduce indebtedness, primarily commercial paper.

During 2003, we acquired approximately 200 natural gas-producing wells for a cash purchase price of $168 million. We also acquired a long-term full-requirements power supply agreement with Jackson Electric Membership Corporation (Jackson) for a cash payment of $188 million (See Notes 4C and 4D).

FINANCING ACTIVITIES

Net cash provided by (used in) financing activities for the three years ending December 31, 2005, 2004 and 2003, was $227 million, $(731) million and $(188) million, respectively. See Note 12 for details of debt and credit facilities.

For 2005, cash provided by financing activities increased primarily due to additional issuances of long-term debt at the Utilities in 2005 and an increase in common stock issuances.

For 2004 and 2003, cash from operations exceeded net cash used in investing activities by $754 million and $172 million, respectively, due primarily to asset sales, which allowed for a net decrease in cash requirements provided by financing activities.

In addition to the financing activities discussed under "Overview," our financing activities included:

2006

- On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010. These senior notes are unsecured. Interest on the Floating Rate Senior Notes will be based on three-month London Inter Bank Offering Rate (LIBOR) plus 45 basis points and will be reset quarterly. We used the net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006. Pending the application of proceeds as described above, we invested the net proceeds in short-term, interest-bearing, investment-grade securities.

2005

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2005:

(in millions)	Description	Total	Outstanding	Reserved[a]	Available
Progress Energy, Inc.	Five-year (expiring 8/5/09)	$1,130	$–	$(150)	$980
PEC	Five-year (expiring 6/28/10)	450	–	(73)	377
PEF	Five-year (expiring 3/28/10)	450	–	(102)	348
Total credit facilities		$2,030	$–	$(325)	$1,705

[a] To the extent amounts are reserved for commercial paper outstanding, they are not available for additional borrowings. In addition, at December 31, 2005 and 2004, Progress Energy, Inc. had a total amount of $150 million reserved for backing of letters of credit. At December 31, 2005, the actual amount of letters of credit issued was $33 million.

- In January 2005, Progress Energy used proceeds from the issuance of commercial paper to pay off $260 million of RCA loans at the Utilities, which included $90 million at PEC and $170 million at PEF. PEF subsequently used money pool borrowings to reduce its outstanding commercial paper balance.
- On January 31, 2005, Progress Energy entered into a new $600 million RCA, which was scheduled to expire on December 30, 2005. This facility was added to provide additional liquidity, to the extent necessary, during 2005 due in part to the uncertainty of the timing of storm restoration cost recovery from the hurricanes in Florida during 2004. On February 4, 2005, $300 million was drawn under the Progress Energy $600 million RCA to reduce commercial paper and pay off the remaining amount of loans outstanding under other RCA facilities, which consisted of $160 million at Progress Energy and, through the money pool, $55 million at PEF. As discussed below, the maximum size of the Progress Energy RCA was reduced to $300 million on March 22, 2005, and subsequently terminated on May 16, 2005.
- On March 22, 2005, PEC issued $300 million of First Mortgage Bonds, 5.15% Series due 2015, and $200 million of First Mortgage Bonds, 5.70% Series due 2035. The net proceeds from the sale of the bonds were used to pay at maturity $300 million of PEC's 7.50% Senior Notes on April 1, 2005, and reduce the outstanding balance of PEC's commercial paper. Pursuant to the terms of Progress Energy's $600 million RCA, commitments were reduced to $300 million, effective March 22, 2005.
- In March 2005, Progress Energy's $1.1 billion five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65 percent to 68 percent due to the potential impacts of a proposed interpretation of SFAS No. 109 regarding accounting rules for uncertain tax positions (See Note 2).
- On March 28, 2005, PEC entered into a new $450 million five-year RCA with a syndication of financial institutions. The PEC RCA will be used to provide liquidity support for PEC's issuances of commercial paper and other short-term obligations. The PEC RCA is scheduled to expire on June 28, 2010. The new $450 million PEC RCA replaced PEC's $285 million three-year RCA and $165 million 364-day RCA, which were each terminated effective March 28, 2005. Fees and interest rates under the new PEC RCA are to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P. The PEC RCA includes a defined maximum total debt to capital ratio of 65 percent. The PEC RCA also contains various cross-default and other acceleration provisions, including a cross-default provision for defaults of indebtedness in excess of $35 million. The PEC RCA does not include a no material adverse change representation for borrowings or a financial covenant for interest coverage.
- On March 28, 2005, PEF entered into a new $450 million five-year RCA with a syndication of financial institutions. The PEF RCA will be used to provide liquidity support for PEF's issuances of commercial paper and other short-term obligations. The PEF RCA is scheduled to expire on March 28, 2010. The new $450 million PEF RCA replaced PEF's $200 million three-year RCA and $200 million 364-day RCA, which were each terminated effective March 28, 2005. Fees and interest rates under the new PEF RCA are to be determined based upon the credit rating of PEF's long-term unsecured senior noncredit enhanced debt, currently rated as A3 by Moody's and BBB- by S&P. The PEF RCA includes a defined maximum total debt to capital ratio of 65 percent. The PEF RCA also contains various cross-default and other acceleration provisions, including a cross-default provision for defaults of indebtedness in excess of $35 million. The PEF RCA does not include a no material adverse change representation for borrowings or a financial covenant for interest coverage.
- In May 2005, Progress Energy used proceeds from the issuance of commercial paper to pay off $300 million of its $600 million RCA.
- On May 16, 2005, PEF issued $300 million of First Mortgage Bonds, 4.50% Series due 2010. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of commercial paper. Pursuant to the terms of the Progress Energy $600 million RCA, commitments were completely reduced and the Progress Energy $600 million RCA was terminated, effective May 16, 2005.
- On July 1, 2005, PEF paid at maturity $45 million of its 6.72% Medium-Term Notes, Series B with commercial paper proceeds.
- On July 28, 2005, PEC filed a shelf registration statement with the SEC to provide $1.0 billion of capacity. The registration statement was declared effective on December 23, 2005, and will allow PEC to issue various securities, including First Mortgage Bonds, Senior Notes, Debt Securities and Preferred Stock.
- On July 28, 2005, PEF filed a shelf registration statement with the SEC to provide $1.0 billion of capacity. The registration statement was declared

effective on December 23, 2005, and will allow PEF to issue various securities, including First Mortgage Bonds, Debt Securities and Preferred Stock.

- In addition to the ongoing RCAs, Progress Energy entered into a new $800 million 364-day credit agreement on November 21, 2005, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, we retired $800 million of our 6.75% Senior Notes, thus effectively terminating the 364-day credit agreement.
- On November 30, 2005, PEC issued $400 million of First Mortgage Bonds, 5.25% Series due 2015. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of short-term debt, including commercial paper borrowings and borrowings under our internal money pool, and for general corporate purposes.
- On December 13, 2005, PEF issued $450 million of Series A Floating Rate Senior Notes due 2008. These senior notes are unsecured. Interest on the Floating Rate Senior Notes will be based on three-month LIBOR plus 40 basis points and will be reset quarterly. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of short-term debt, including commercial paper borrowings and borrowings under our internal money pool, and for general corporate purposes.
- Progress Energy issued approximately 4.8 million shares of our common stock for approximately $208 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans, net of purchases of restricted shares. For 2005, the dividends paid on common stock were approximately $582 million.

2004

- Progress Energy paid at maturity $500 million in senior unsecured notes and entered into a new $1.1 billion five-year line of credit, expiring August 5, 2009. This facility replaced Progress Energy's $250 million 364-day line of credit and its three-year $450 million line of credit, which were both scheduled to expire in November 2004. Proceeds from the sale of natural gas assets were used to extinguish Genco's $241 million bank facility, and Progress Capital Holdings, Inc., paid at maturity $25 million of Medium-Term Notes.
- PEC redeemed $39 million of Pollution Control Obligations and paid at maturity $300 million in First Mortgage Bonds. PEC extended to July 27, 2005, its $165 million 364-day line of credit, which was scheduled to expire on July 29, 2004.
- PEF paid at maturity $40 million in Medium-Term Notes.
- Progress Energy issued approximately 1.7 million shares of our common stock for approximately $73 million in net proceeds from our Investor Plus Stock Purchase Plan and our employee benefit and stock option plans, net of purchases of restricted shares. For 2004, the dividends paid on common stock were approximately $558 million.

2003

- Progress Energy obtained a three-year financing order, allowing it to issue up to $2.8 billion of long-term securities, $1.5 billion of short-term debt, and $3 billion in parent guarantees. Progress Capital Holdings, Inc., paid at maturity $58 million in Medium-Term Notes. Genco terminated its $50 million working capital credit facility. Under its related construction facility, Genco had drawn $241 million at December 31, 2003.
- PEC redeemed $250 million and issued $600 million in First Mortgage Bonds.
- PEF redeemed $250 million, issued $950 million and paid at maturity $180 million in First Mortgage Bonds. PEF also paid at maturity $35 million in Medium-Term Notes.
- Progress Energy issued approximately 7.6 million shares of common stock for approximately $304 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit plans, net of purchases of restricted shares. For 2003, the dividends paid on common stock were approximately $541 million.

Future Liquidity and Capital Resources

Please review "SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS" for a discussion of the factors that may impact any such forward-looking statements made herein.

The Utilities produced approximately 100 percent of consolidated cash from operations in 2005 and over 100 percent of consolidated cash from operations in 2004. It is expected that the Utilities will continue to produce a majority of the consolidated cash flows from operations over the next several years as our nonregulated investments, primarily generation assets, improve asset utilization and increase their operating cash flows. Cash from operations plus availability under current debt agreements is expected to be sufficient to meet our requirements in the near term. To the extent necessary we may also access the capital markets or use limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans to meet our liquidity requirements.

The amount and timing of future sales of company securities will depend on market conditions, operating cash flow, asset sales and our specific needs. We may from time to time sell securities beyond the amount needed to meet capital requirements in order to allow for the early redemption of long-term debt, the redemption of preferred stock, the reduction of short-term debt or for other general corporate purposes.

At December 31, 2005, the current portion of our long-term debt was $513 million. We classified $397 million related to the retirement of $800 million of Progress Energy, Inc. 6.75% Senior Notes on March 1, 2006, as long-term debt. Settlement of this obligation is not expected to require the use of working capital in 2006 as we have the intent and ability to refinance this debt on a long-term basis. We used the net proceeds of $397 million from the aforementioned issuance of $300 million 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010, and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006.

The following regulatory matters may impact our future liquidity and financing activities. See Note 7 for further discussion of these regulatory matters.

On April 27, 2005, PEC filed for an increase in the fuel rate charged to its South Carolina retail customers with the SCPSC. PEC requested the $99 million increase for under-recovered fuel costs for the previous 15 months and to meet future expected fuel costs. On June 23, 2005, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceeding. The settlement agreement levelizes the collection of under-recovered fuel costs over a three-year period ending June 30, 2008, and allows PEC to charge and recover carrying costs on the monthly unpaid balance, beginning July 1, 2006, at an interest rate of 6% compounded annually. An annual increase in PEC's rates of $55 million, or 12 percent, was effective July 1, 2005.

On June 3, 2005, PEC filed for an increase in the fuel rate charged to its North Carolina retail customers with the NCUC. PEC requested that the NCUC approve an annual increase of $276 million, or 11 percent. PEC requested the increase for under-recovered fuel costs for the previous 12 months and to meet future expected fuel costs. On September 26, 2005, the NCUC approved a settlement agreement proposed by PEC and other parties to the proceeding. In the settlement, PEC will collect all of its fuel cost under-collections that occurred during the test year ended March 31, 2005, over a one-year period beginning October 1, 2005. PEC agreed to reduce its proposed billing increment, designed to collect future fuel costs, in order to address customer concerns regarding the magnitude of the proposed increase. The NCUC approved an annual increase of $133 million, an average increase of 5 percent. In recognition of the likely under-collection that will result during the 12 months ending September 30, 2006, PEC is allowed to calculate and collect interest at 6% on the difference between its collection factor in the original request to the NCUC and the factor included in the settlement agreement until such amounts have been collected. The increase was effective October 1, 2005. At December 31, 2005, PEC's North Carolina retail fuel costs were under-recovered by $254 million. This amount was comprised of $244 million eligible for recovery in 2006 and $10 million deferred from a 2001 NCUC order that cannot be collected until 2007.

On November 9, 2005, the FPSC approved PEF's filed request seeking a total increase of $605 million over 2005 to recover rising fuel costs as well as costs related to other pass-through clauses and surcharges. Fuel costs of $560 million and certain purchased power costs of $42 million were the largest component of the total increase. The fuel cost increase includes $17 million from 2004 under-recoveries, $222 million from 2005 under-recoveries and a $321 million increase for 2006. Beginning January 1, 2006, residential electric bills increased by $11.78 per 1,000 kWhs each billing cycle through December 31, 2006. At December 31, 2005, PEF was under-recovered in fuel and capacity costs by $341 million.

On September 7, 2005, the FPSC approved an agreement (Base Rate Settlement) that maintains PEF's base rates at the current level through late 2007, except as modified elsewhere in the Base Rate Settlement. The new base rates took effect the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009 with PEF having sole option to extend through the last billing cycle of June 2010.

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million of storm costs, including interest, over a two-year period, effective August 1, 2005. PEF's initial petition in November 2004 for $252 million was an estimate. On September 12, 2005, PEF filed a true-up for an additional $19 million in storm costs in excess of the amount requested in the original petition. The recovery of this difference, net of approximately $6 million of adjustments, was administratively approved by the FPSC, subject to audit by the FPSC staff. The impact was included in customer bills beginning January 1, 2006.

On June 1, 2005, the governor of Florida signed into law a bill that allows utilities to petition the FPSC to use securitized bonds to recover storm-related costs. PEF is reviewing whether it will seek FPSC approval to issue securitized debt to recover any outstanding balance of its 2004 storm costs and to replenish its storm reserve fund, or to continue the current replenishment of its storm reserve fund through base rates and a surcharge mechanism. If PEF seeks recovery through securitization and assuming FPSC approval, PEF expects the process to take six to nine months to complete.

In addition, our synthetic fuel operations do not currently produce positive operating cash flow due to the difference in timing of when tax credits are recognized for financial reporting purposes and when tax credits are realized for tax purposes (See Note 23D).

CAPITAL EXPENDITURES

Total cash from operations provided the funding for our capital expenditures, including property additions, nuclear fuel expenditures and diversified business property additions during 2005, excluding proceeds from asset sales of $475 million.

As shown in the table below, we expect the majority of our capital expenditures to be incurred at our regulated operations. We anticipate our regulated capital expenditures will increase in 2006 and 2007, primarily due to increased spending on environmental initiatives. Forecasted nonregulated expenditures relate primarily to Progress Ventures and its gas operations, mainly for drilling new wells.

	Actual	Forecasted		
(in millions)	**2005**	2006	2007	2008
Regulated capital expenditures	**$1,080**	$1,520	$1,400	$1,600
Nuclear fuel expenditures	**126**	70	160	140
AFUDC – borrowed funds	**(13)**	(10)	(20)	(30)
Nonregulated capital and other expenditures	**228**	190	190	190
Total	**$1,421**	$1,770	$1,730	$1,900

Regulated capital expenditures for 2006, 2007 and 2008 in the table above include approximately $370 million, $420 million and $560 million, respectively, for environmental compliance capital expenditures. We currently estimate total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, a portion of which are eligible for regulatory recovery, to be in excess of $2.0 billion through 2018, which is the latest compliance target date for current air and water quality regulations. See Note 22 for further discussion of our environmental compliance costs and related recovery of costs.

All projected capital and investment expenditures are subject to periodic review and revision and may vary significantly depending on a number of factors including, but not limited to, industry restructuring, regulatory constraints, market volatility and economic trends.

OTHER CASH NEEDS

During the fourth quarter of 2004, we announced the launch of a new cost-management initiative. This cost-management initiative is designed to permanently reduce, by $75 million to $100 million, our projected growth in annual nonfuel O&M expenses by the end of 2007. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, which will be paid over time (See Note 17). We do not expect to incur any similar charges during 2006.

CREDIT FACILITIES

At December 31, 2005, we had committed revolving credit facilities and available balances as shown in the table in Note 12. All of the revolving credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities.

Our internal financial policy precludes issuing commercial paper in excess of the supporting lines of credit. At December 31, 2005, we had $175 million reserved for outstanding commercial paper balance and a total of $150 million reserved for backing of letters of credit, leaving an additional $1.705 billion available for future borrowing under our credit lines. At December 31, 2005, the actual amount of letters of credit issued was $33 million. In addition, we have requirements to pay minimal annual commitment fees to maintain our credit facilities. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings.

In addition to the committed RCAs at December 31, 2005, we had an $800 million 364-day credit agreement, which was restricted for the retirement of $800 million of 6.75% Senior Notes on March 1, 2006. On March 1, 2006, Progress Energy retired $800 million of its 6.75% Senior Notes, thus effectively terminating the 364-day credit agreement.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage). Progress Energy's RCA includes a minimum interest coverage ratio. We are currently in compliance with these covenants and were in compliance with these covenants at December 31, 2005. See Note 12 for a discussion of the credit facilities' financial covenants, material adverse change clause provisions and cross-default provisions.

Progress Energy has on file with the SEC a shelf registration statement under which senior debt securities, junior subordinated debentures, common and preferred stock and other trust preferred securities, among other securities, are available for issuance. At December 31, 2005, there was approximately $1.1 billion available under this shelf registration. As a result of the $300 million and $100 million issuances on January 13, 2006, discussed above in "Financing Activities," the amount available under this shelf registration statement was subsequently reduced to $679 million.

Both PEC and PEF currently have on file with the SEC a shelf registration statement under which each can issue up to $1.0 billion of various long-term debt securities and preferred stock.

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2005, PEC and PEF could issue up to $3.08 billion and $3.54 billion, respectively, based on property additions and $1.63 billion and $0.18 billion, respectively, based upon retirements.

The following table shows our total debt to total capitalization ratios at December 31:

	2005	2004
Common stock equity	41.6%	41.7%
Preferred stock and minority interest	0.7%	0.7%
Total debt	57.7%	57.6%

CREDIT RATING MATTERS

The major credit rating agencies have currently rated our securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Progress Energy, Inc.			
Outlook	Negative	Stable	Stable
Corporate credit rating	n/a	BBB	n/a
Senior unsecured debt	Baa2	BBB-	BBB-
Commercial paper	P-2	A-2	n/a
PEC			
Outlook	Stable	Stable	Stable
Corporate credit rating	Baa1	BBB	n/a
Commercial paper	P-2	A-2	F2
Senior secured debt	A3	BBB	A-
Senior unsecured debt	Baa1	BBB-	BBB+
Preferred stock	Baa3	BB+	BBB
PEF			
Outlook	Stable	Stable	Stable
Corporate credit rating	A3	BBB	n/a
Commercial paper	P-2	A-2	F2
Senior secured debt	A2	BBB	A-
Senior unsecured debt	A3	BBB-	BBB+
Preferred stock	Baa2	BB+	BBB
FPC Capital I			
Preferred stock[a]	Baa2	BB+	n/a
Progress Capital Holdings, Inc.			
Senior unsecured debt[a]	Baa1	BBB-	n/a

[a] Guaranteed by Progress Energy, Inc. and Florida Progress.

These ratings reflect the current views of these rating agencies, and no assurances can be given that these ratings will continue for any given period of time. However, we monitor our financial condition as well as market conditions that could ultimately affect our credit ratings.

On February 11, 2005, Moody's announced that it lowered the ratings of PEF, Progress Capital Holdings, Inc. and FPC Capital Trust I and changed their rating outlooks to stable from negative. Moody's affirmed the ratings of Progress Energy and PEC. The rating outlooks continue to be stable at PEC and negative at Progress Energy. Moody's stated that it took this action primarily due to declining cash flow coverages and rising leverage, higher O&M costs, uncertainty regarding the timing of hurricane cost recovery, regulatory risks associated with the then upcoming rate case in Florida and ongoing capital requirements to meet Florida's growing demand.

On November 22, 2005, S&P announced that it revised its ratings outlook on Progress Energy from negative to stable, affirming the BBB corporate credit rating, and revising the short-term rating from A-3 to A-2. As a result of this revision, PEC's and PEF's outlooks and short-term ratings were also revised from negative to stable and A-3 to A-2, respectively. S&P stated that it took these actions primarily due to the resolution of several regulatory issues in Florida and expectations of increased likelihood that the financial performance will improve over the next two years. S&P also indicated that it has improved its business position for PEF to a '4' (strong). The business position for PEC remains a '5' (satisfactory) and the overall business position for Progress Energy remains at a '6' (satisfactory). S&P ranks business position on a scale of '1' (excellent) to '10' (vulnerable).

On December 6, 2005, S&P lowered the BBB rating on PEC's and PEF's senior unsecured notes to BBB-. The revision reflects the recognition that a significant amount of the Utilities' assets (more than 30 percent of PEC's assets and 35 percent of PEF's assets) collateralize first-priority debt.

The changes by S&P and Moody's did not trigger any debt or guarantee collateral requirements, nor did they have any material impact on the overall liquidity of Progress Energy or any of its affiliates. Fitch Ratings took no actions on Progress Energy's, PEC's or PEF's ratings in 2005. To date, Progress Energy's, PEC's and PEF's access to the commercial paper markets has not been materially impacted by the rating agencies' actions.

Our debt indentures and credit agreements do not contain any "ratings triggers," which would cause the acceleration of interest and principal payments in the event of a ratings downgrade. If S&P lowers Progress Energy's senior unsecured rating one ratings category to BB+ from its current rating, it would be a noninvestment grade rating. The effect of a noninvestment grade rating would primarily be increased borrowing costs. Our liquidity would essentially remain unchanged, as we believe we could borrow under our revolving credit facilities instead of issuing commercial paper for our short-term borrowing needs. However, we have certain contracts that have provisions triggered by a ratings downgrade to a rating below investment grade. A noninvestment grade rating by S&P or Moody's would trigger additional funding requirements of approximately $540 million due to ratings triggers embedded in various contracts, as more fully described below under "Guarantees." While we believe that we would be able to meet this obligation with cash or letters of credit, if we cannot, our financial condition, liquidity and results of operations will be materially and adversely impacted. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

Our off-balance sheet arrangements and contractual obligations are described below.

Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties that are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN No. 45). These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2005, we have issued $1.78 billion of guarantees for future financial or performance assurance. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 24). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

The majority of contracts supported by the guarantees contain provisions that trigger guarantee obligations based on downgrade events to below investment grade (below BBB- or Baa3) by S&P or Moody's, ratings triggers, monthly netting of exposure and/or payments and offset provisions in the event of a default. At December 31, 2005, no guarantee obligations had been triggered. If the guarantee obligations were triggered, the approximate amount of liquidity requirements to support ongoing operations within a 90-day period, associated with guarantees for Progress Energy's nonregulated portfolio and power supply agreements, was $540 million. While we believe that we would be able to meet this obligation with cash or letters of credit, if we cannot, our financial condition, liquidity and results of operations will be materially and adversely impacted.

At December 31, 2005, we have issued guarantees and indemnifications of certain legal, tax and environmental matters to third parties in connection with sales of businesses and for timely payment of obligations in support of our nonwholly owned synthetic fuel operations. Related to the sales of businesses, the notice period extends until 2012 for the majority of matters provided for in the indemnification provisions. For matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain environmental indemnifications have no limitations as to time or maximum potential future payments. Other guarantees and indemnifications have an estimated maximum exposure of approximately $152 million. Additionally, in 2005 PEC entered into a contract with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a $16 million liability related to this indemnification (See Note 22B). At December 31, 2005, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $41 million. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

Market Risk and Derivatives

Under our risk management policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 18 for a discussion of market risk and derivatives.

Contractual Obligations

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Amounts in the following table are estimated based upon contractual terms and actual amounts will likely differ from amounts presented below. Further disclosure regarding our contractual obligations is included in the respective notes. We take into consideration the future commitments when assessing our liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2005, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt[a] (See Note 12)	$11,052	$513	$1,951	$807	$7,781
Interest payments on long-term debt and interest rate derivatives[b]	6,994	637	1,160	964	4,233
Capital lease obligations (See Note 23B)	149	4	18	18	109
Operating leases (See Note 23B)	706	76	176	156	298
Fuel and purchased power[c] (See Note 23A)	14,714	3,257	4,243	1,741	5,473
Other purchase obligations (See Note 23A)	694	163	194	105	232
Minimum pension funding requirements[d]	274	10	241	23	–
Other commitments[e][f]	203	44	40	27	92
Total	$34,786	$4,704	$8,023	$3,841	$18,218

[a] Our maturing debt obligations are generally expected to be refinanced with new debt issuances in the capital markets.

[b] Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective at December 31, 2005, and the LIBOR forward curve at December 31, 2005, respectively.

[c] Fuel and purchased power commitments represent the majority of our remaining future commitments after debt obligations. Essentially all of our fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.

[d] Projected pension funding status is based on current actuarial estimates and is subject to future revision.

[e] In 2008, PEC must begin transitioning amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.

[f] We have certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties) through 2007 (See Note 23D).

OTHER MATTERS

Synthetic Fuels Tax Credits

We have substantial operations associated with the production of coal-based synthetic fuels. The production and sale of these products qualifies for federal income tax credits so long as certain requirements are satisfied. These operations are subject to various risks.

For 2005 and prior years, our ability to claim tax credits was dependent on having sufficient tax liability. Any conditions that negatively impact our tax liability, such as weather, could also diminish our ability to claim or utilize credits, including those previously generated. Beginning in 2006, Section 29 tax credits have been redesignated as a Section 45K general business credit, which removes the regular federal income tax liability limit on synthetic fuel production and subjects the credits to a 20-year carry forward period. Synthetic fuel is generally not economical to produce absent the credits. In addition, the tax credits associated with synthetic fuels in a particular year may be phased out if Annual Average market prices for crude oil exceed certain prices.

Our synthetic fuel operations and related risks are described in more detail in Note 23D.

Regulatory Environment

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, SCPSC and the FPSC, respectively. The electric businesses are also subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and other federal and state agencies common to the utility business. In addition, until February 8, 2006, we were subject to SEC regulation as a registered holding company under PUHCA. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the Utilities are permitted to earn, are subject to the approval of these governmental agencies.

PEC and PEF continue to monitor developments impacting competition and have actively participated in regulatory reform deliberations in North Carolina, South Carolina and Florida. Movement toward deregulation throughout the nation has effectively ceased due to numerous factors including but not limited to California's experience with retail deregulation and the Enron situation. We expect the legislatures in all three states will continue to monitor the experiences of states that have implemented electric restructuring legislation. We cannot anticipate when, or if, any of these states will move to increase competition in the electric industry.

The retail rate matters affected by the regulatory authorities are discussed in detail in Notes 7B and 7C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects to our consolidated financial statements.

The regulatory authorities continue to evaluate issues related to the timing, creation and structure of transmission organizations. We cannot predict the outcome of these matters (See Note 7D).

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market-based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. In July 2004, the FERC issued a second order that re-affirmed its April order and initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. PEF does not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believes it would experience in passing one of the interim screens, on September 6, 2005, PEC filed revisions to its market-based rate tariffs restricting them to sales outside of PEC's control area and peninsular Florida and a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs.

Legal

We are subject to federal, state and local legislation and court orders. These matters are discussed in detail in Note 23D. This discussion identifies specific issues, the status of the issues, accruals associated with issue resolutions and the associated exposures to us.

Nuclear

Nuclear generating units are regulated by the NRC. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit or some combination of these, depending upon its assessment of the severity of the situation, until compliance is achieved.

Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications (See Notes 5 and 23D).

Due to the anticipated growth in our service territories, we anticipate we will need to increase our baseload generation in both Florida and the Carolinas within the next decade. We are currently evaluating our options for future baseload generation needs. Both nuclear and coal technologies are being explored in parallel paths. At this time, no definitive decision has been made.

We have announced that we are pursuing development of Combined License (COL) applications. Our announcement is not a commitment to build a nuclear plant. It is a necessary step to keep open the option of building a potential plant or plants. On January 23, 2006, we announced that PEC has selected the Shearon Harris Nuclear Plant (Harris) site to evaluate for possible future nuclear expansion and we announced the selection of the Westinghouse Electric AP-1000 reactor design as the technology upon which to base the potential application submission. We currently expect to file the application for the COL for PEC's Harris site in late September or early October 2007. We expect to file the application for the COL for an as-yet unspecified site in Florida in late 2007 or first quarter 2008. We plan to announce the selection of the Florida site in spring 2006. If we receive approval from the NRC, and if the decision to build is made, construction could begin as early as 2010, and a new plant could be online around 2016. We estimate that it will take approximately 36 months for the NRC to review the COL applications and grant approval.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by the Energy Policy Act of 2005 (EPACT). EPACT provides for an annual tax credit of 1.8 cents/kWh for nuclear facilities for the first eight years of operation. The credit is limited to the first 6,000 MW of new nuclear generation in the United States and has an annual cap of $125 million per unit. The credit allocation process among new nuclear plants has not been determined. Other utilities have announced plans to pursue new nuclear plants, and there is no guarantee that any nuclear plant constructed by us would qualify for these additional incentives.

While we currently estimate that we will need to increase our baseload capacity, our assumptions regarding future growth and resulting power demand in our service territories may not be realized. If anticipated growth levels are not realized, we may increase our baseload capacity and have excess capacity. This excess capacity may exceed reserve margins established by the NCUC, SCPSC and FPSC to meet our obligation to serve retail customers and, as a result, may not be recoverable in base rates.

Environmental Matters

We are subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. These environmental matters are discussed in detail in Note 22. This discussion identifies specific environmental issues, the status of the issues, accruals associated with issue resolutions and our associated exposures. We accrue costs to the extent our liability is probable and the costs can be reasonably estimated. It is probable that additional losses, which could be material, may be incurred in the future.

New Accounting Standards

See Note 2 for a discussion of the impact of new accounting standards.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks related to changes in market conditions. Market risk represents the potential loss arising from adverse changes in market rates and prices. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk to the extent that the counterparty fails to perform under the contract. We mitigate such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties (See Note 18).

The following disclosures about market risk contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS" for a discussion of the factors that may impact any such forward-looking statements made herein.

Certain market risks are inherent in our financial instruments, which arise from transactions entered into in the normal course of business. Our primary exposures are changes in interest rates with respect to our long-term debt and commercial paper, fluctuations in the return on marketable securities with respect to our nuclear decommissioning trust funds, changes in the market value of CVOs, and changes in energy-related commodity prices.

These financial instruments are held for purposes other than trading. The risks discussed below do not include the price risks associated with nonfinancial instrument transactions and positions associated with our operations, such as purchase and sales commitments and inventory.

Interest Rate Risk

From time to time, we use interest rate derivative instruments to adjust the mix between fixed- and floating-rate debt in our debt portfolio, to mitigate our exposure to interest rate fluctuations associated with certain debt instruments, and to hedge interest rates with regard to future fixed-rate debt issuances.

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the risk in the transaction is the cost of replacing the agreements at current market rates. We enter into interest rate derivative agreements only with banks with credit ratings of single A or better.

We use a number of models and methods to determine interest rate risk exposure and fair value of derivative positions. For reporting purposes, fair values and exposures of derivative positions are determined as of the end of the reporting period using the Bloomberg Financial Markets system.

In accordance with SFAS No. 133, "Accounting for Derivative and Hedging Activities" (SFAS No. 133), interest rate derivatives that qualify as hedges are broken into one of two categories: cash flow hedges or fair value hedges. Cash flow hedges are used to reduce exposure to changes in cash flow due to fluctuating interest rates. Fair value hedges are used to reduce exposure to changes in fair value due to interest rate changes.

The following tables provide information at December 31, 2005 and 2004, about our interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and FPC obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of our interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates for 2006 to 2010 and thereafter and the fair value of the related hedges. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See Note 18 for more information on interest rate derivatives.

At December 31, 2005, we classified $397 million related to the retirement of $800 million of Progress Energy, Inc. 6.75% Senior Notes on March 1, 2006, as long-term debt. Settlement of this obligation is not expected to require the use of working capital in 2006 as we have the intent and ability to refinance this debt on a long-term basis. On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010, receiving net proceeds of $397 million. These senior notes are unsecured.

(dollars in millions) December 31, 2005	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value
Fixed-rate long-term debt[a]	$513	$674	$827	$401	$306	$6,611	$9,332	$9,768
Average interest rate	6.79%	6.41%	6.27%	5.95%	4.53%	6.34%	6.29%	
Variable-rate long-term debt	–	–	$450	–	$100	$861	$1,411	$1,411
Average interest rate	–	–	4.88%	–	5.03%	3.05%	3.77%	
Debt to affiliated trust[b]	–	–	–	–	–	$309	$309	$312
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Pay variable/receive fixed	–	–	$ (100)	–	–	$(50)	$(150)	$(2)
Average pay rate	–	–	(c)	–	–	(c)	(c)	
Average receive rate	–	–	4.10%	–	–	4.65%	4.28%	
Interest rate forward contracts	–	–	–	–	–	$100	$100	$1
Average pay rate	–	–	–	–	–	4.87%	4.87%	
Average receive rate	–	–	–	–	–	(c)	(c)	

[a] Excludes $397 million in 2006 classified as long-term debt at December 31, 2005.
[b] FPC Capital I – Quarterly Income Preferred Securities.
[c] Rate is 3-month LIBOR, which was 4.54% at December 31, 2005.

(dollars in millions) December 31, 2004	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
Fixed-rate long-term debt	$349	$908	$674	$827	$400	$5,399	$8,557	$9,454
Average interest rate	7.38%	6.78%	6.41%	6.27%	5.95%	6.55%	6.54%	
Variable-rate long-term debt	–	$55	–	–	$160	$861	$1,076	$1,077
Average interest rate	–	2.95%	–	–	3.19%	1.70%	1.99%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$312
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Pay variable/receive fixed	–	–	–	$(100)	–	$(50)	$(150)	$3
Average pay rate	–	–	–	(b)	–	(b)	(b)	
Average receive rate	–	–	–	4.10%	–	4.65%	4.28%	
Interest rate forward contracts	$200	–	–	–	–	$131	$331	$(2)
Average pay rate	3.07%	–	–	–	–	4.90%	3.79%	
Average receive rate	(c)	–	–	–	–	(b)	(b)/(c)	

[a] FPC Capital I – Quarterly Income Preferred Securities.
[b] Rate is 3-month LIBOR, which was 2.56% at December 31, 2004.
[c] Rate is 1-month LIBOR, which was 2.40% at December 31, 2004.

Marketable Securities Price Risk

The Utilities maintain trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning their nuclear plants. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. At December 31, 2005 and 2004, the fair value of these funds was $1.133 billion and $1.044 billion, respectively, including $640 million and $581 million, respectively, for PEC and $493 million and $463 million, respectively, for PEF. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of FPC, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuel facilities purchased by subsidiaries of FPC in October 1999. The payments, if any, are based on the net after-tax cash flows the facilities generate. These CVOs are recorded at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. At December 31, 2005 and 2004, the fair value of these CVOs was $7 million and $13 million, respectively. A hypothetical 10 percent decrease in the December 31, 2005, market price would result in a $1 million decrease in the fair value of the CVOs.

Commodity Price Risk

We are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of our ownership of energy-related assets. Our exposure to these fluctuations is significantly limited by the cost-based regulation of the Utilities. Each state commission allows electric utilities to recover certain of these costs through various cost recovery clauses to the extent the respective commission determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. In addition, many of our long-term power sales contracts shift substantially all fuel responsibility to the purchaser. We also have oil price risk exposure related to synthetic fuel tax credits (See Note 23D).

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity positions. We exclude the impact of derivative commodity instruments that are recovered through cost-based regulation at PEF from this analysis. A hypothetical 10 percent increase or decrease in commodity market prices in the near term on our derivative commodity instruments would not have had a material effect on our financial position, results of operations or cash flows at December 31, 2005 and 2004.

See Note 18 for additional information with regard to our commodity contracts and use of derivative financial instruments.

Economic Derivatives

Derivative products, primarily electricity and natural gas contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to our results of operations during 2005, 2004 and 2003. We did not have material outstanding positions in such contracts at December 31, 2005 and 2004, other than those receiving regulatory accounting treatment at PEF, as discussed below.

PEF has derivative instruments related to its exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits, and a $6 million long-term derivative liability position included in other liabilities and deferred credits. At December 31, 2004, the fair values of the instruments were a $2 million long-term derivative asset position included in other assets and deferred debits and a $5 million short-term derivative liability position included in other current liabilities.

Cash Flow Hedges

We use natural gas and power hedging instruments to manage a portion of the market risk associated with fluctuations in the future purchase and sales prices of natural gas and power. Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133.

The fair values of commodity cash flow hedges at December 31 were as follows:

(in millions)	2005	2004
Fair value of assets	$170	$–
Fair value of liabilities	(58)	(15)
Fair value, net	$112	$(15)

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of Progress Energy's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15(d)-15(f) of the Securities Exchange Act of 1934, as amended. Progress Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America. Internal control over financial reporting include policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Progress Energy; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles in the United States of America; (3) provide reasonable assurance that receipts and expenditures of Progress Energy are being made only in accordance with authorizations of management and directors of Progress Energy; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Progress Energy's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of Progress Energy's internal control over financial reporting at December 31, 2005. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of the board of directors.

Based on our assessment, management determined that, at December 31, 2005, Progress Energy maintained effective internal control over financial reporting.

Management's assessment of the effectiveness of Progress Energy's internal control over financial reporting at December 31, 2005, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

Robert B McGehee

Robert B. McGehee
Chairman and Chief Executive Officer

Peter M. Scott III

Peter M. Scott III
Executive Vice President and Chief Financial Officer

March 6, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.

We have audited management's assessment, included in the accompanying Management's Report of Internal Controls, that Progress Energy, Inc., and its subsidiaries (the "Company") maintained effective internal control over financial reporting at December 31, 2005, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting at December 31, 2005, is fairly stated, in all material respects, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting at December 31, 2005, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2005, of the Company and our report dated March 6, 2006, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph regarding the Company's adoption of Statement of Financial Accounting Standard No. 123R and Financial Accounting Standards Board Interpretation No. 47.

Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2005 and 2004, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 the Company at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 and Note 18 to the consolidated financial statements, in 2005 the Company adopted Statement of Financial Accounting Standards No. 123R and Financial Accounting Standards Board Interpretation No. 47 and in 2003 the Company adopted Statement of Financial Accounting Standards No. 143 and Derivatives Implementation Group Issue C20.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting at December 31, 2005, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 6, 2006, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data)

Years ended December 31	2005	2004	2003
Operating revenues			
Electric	**$7,945**	$7,153	$6,741
Diversified business	**2,163**	1,372	1,058
Total operating revenues	**10,108**	8,525	7,799
Operating expenses			
Utility			
Fuel used in electric generation	**2,359**	2,011	1,695
Purchased power	**1,048**	868	862
Operation and maintenance	**1,770**	1,475	1,421
Depreciation and amortization	**922**	878	883
Taxes other than on income	**460**	425	405
Other	**(37)**	(13)	(8)
Diversified business			
Cost of sales	**2,075**	1,179	929
Depreciation and amortization	**152**	157	126
(Gain)/loss on the sale of assets	**(34)**	(63)	1
Other	**108**	164	141
Total operating expenses	**8,823**	7,081	6,455
Operating income	**1,285**	1,444	1,344
Other income (expense)			
Interest income	**17**	14	11
Impairment of investments	**(1)**	–	(21)
Other, net	**(5)**	(12)	(27)
Total other income (expense)	**11**	2	(37)
Interest charges			
Net interest charges	**653**	634	614
Allowance for borrowed funds used during construction	**(13)**	(6)	(7)
Total interest charges, net	**640**	628	607
Income from continuing operations before income tax and minority interest	**656**	818	700
Income tax (benefit) expense	**(45)**	106	(113)
Income from continuing operations before minority interest	**701**	712	813
Minority interest in subsidiaries' loss, net of tax	**(26)**	(17)	2
Income from continuing operations	**727**	729	811
Discontinued operations, net of tax	**(31)**	30	(5)
Cumulative effect of changes in accounting principles, net of tax	**1**	–	(24)
Net income	**$697**	$759	$782
Average common shares outstanding – basic	**247**	242	237
Basic earnings per common share			
Income from continuing operations	**$2.95**	$3.01	$3.42
Discontinued operations, net of tax	**(0.13)**	0.12	(0.02)
Cumulative effect of changes in accounting principles, net of tax	**–**	–	(0.10)
Net income	**$2.82**	$3.13	$3.30
Diluted earnings per common share			
Income from continuing operations	**$2.94**	$3.00	$3.40
Discontinued operations, net of tax	**(0.12)**	0.12	(0.02)
Cumulative effect of changes in accounting principles, net of tax	**–**	–	(0.10)
Net income	**$2.82**	$3.12	$3.28
Dividends declared per common share	**$2.38**	$2.32	$2.26

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2005	2004
ASSETS		
Utility plant		
Utility plant in service	**$22,940**	$22,103
Accumulated depreciation	**(9,602)**	(8,783)
Utility plant in service, net	**13,338**	13,320
Held for future use	**12**	13
Construction work in progress	**813**	799
Nuclear fuel, net of amortization	**279**	231
Total utility plant, net	**14,442**	14,363
Current assets		
Cash and cash equivalents	**606**	56
Short-term investments	**191**	82
Receivables, net	**1,103**	896
Inventory	**866**	822
Deferred fuel cost	**602**	229
Deferred income taxes	**50**	112
Assets of discontinued operations	**109**	685
Prepayments and other current assets	**211**	150
Total current assets	**3,738**	3,032
Deferred debits and other assets		
Regulatory assets	**854**	1,064
Nuclear decommissioning trust funds	**1,133**	1,044
Diversified business property, net	**1,880**	1,773
Miscellaneous other property and investments	**477**	444
Goodwill	**3,719**	3,719
Prepaid pension costs	**–**	42
Intangibles, net	**302**	336
Other assets and deferred debits	**478**	227
Total deferred debits and other assets	**8,843**	8,649
Total assets	**$27,023**	$26,044
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 252 million and 247 million shares issued and outstanding, respectively	**$5,571**	$5,360
Unearned restricted shares (1 million shares) (Note 10B)	**–**	(13)
Unearned ESOP shares (3 million and 3 million shares, respectively)	**(63)**	(76)
Accumulated other comprehensive loss	**(104)**	(164)
Retained earnings	**2,634**	2,526
Total common stock equity	**8,038**	7,633
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93
Minority interest	**43**	36
Long-term debt, affiliate	**270**	270
Long-term debt, net	**10,176**	9,251
Total capitalization	**18,620**	17,283
Current liabilities		
Current portion of long-term debt	**513**	349
Accounts payable	**678**	625
Interest accrued	**208**	219
Dividends declared	**152**	145
Short-term obligations	**175**	684
Customer deposits	**200**	180
Liabilities of discontinued operations	**40**	186
Other current liabilities	**879**	695
Total current liabilities	**2,845**	3,083
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**278**	648
Accumulated deferred investment tax credits	**163**	176
Regulatory liabilities	**2,527**	2,654
Asset retirement obligations	**1,249**	1,265
Accrued pension and other benefits	**870**	633
Other liabilities and deferred credits	**471**	302
Total deferred credits and other liabilities	**5,558**	5,678
Commitments and contingencies (Notes 22 and 23)		
Total capitalization and liabilities	**$27,023**	$26,044

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

Years ended December 31	2005	2004	2003
Operating activities			
Net income	$697	$759	$782
Adjustments to reconcile net income to net cash provided by operating activities			
Loss (income) from discontinued operations	31	(30)	5
Gain on sale of operating assets	(71)	(76)	(7)
Impairment of long-lived assets and investments	1	–	21
Cumulative effect of changes in accounting principles, net	(1)	–	24
Charges for voluntary enhanced retirement program	159	–	–
Depreciation and amortization	1,195	1,153	1,110
Deferred income taxes	(351)	(65)	(304)
Investment tax credit	(13)	(14)	(16)
Deferred fuel credit	(317)	(19)	(133)
Other adjustments to net income	160	125	89
Cash provided (used) by changes in operating assets and liabilities			
Receivables	(187)	(4)	(136)
Inventories	(143)	(90)	(26)
Prepayments and other current assets	(20)	2	37
Accounts payable	145	(21)	11
Other current liabilities	213	80	119
Regulatory assets and liabilities	(74)	(234)	26
Other operating activities	50	(1)	(14)
Net cash provided by operating activities	1,474	1,565	1,588
Investing activities			
Gross utility property additions	(1,080)	(998)	(972)
Diversified business property additions	(206)	(169)	(448)
Nuclear fuel additions	(126)	(101)	(117)
Proceeds from sales of discontinued operations and other assets, net of cash divested	475	373	579
Purchases of available-for-sale securities and other investments	(3,985)	(3,134)	(3,792)
Proceeds from sales of available-for-sale securities and other investments	3,845	3,248	3,529
Acquisition of intangibles	(3)	(1)	(200)
Other investing activities	(37)	(29)	5
Net cash used in investing activities	(1,117)	(811)	(1,416)
Financing activities			
Issuance of common stock	208	73	304
Proceeds from issuance of long-term debt, net	1,642	421	1,539
Net (decrease) increase in short-term indebtedness	(509)	680	(696)
Retirement of long-term debt	(564)	(1,353)	(810)
Dividends paid on common stock	(582)	(558)	(541)
Other financing activities	32	6	16
Net cash provided (used) by financing activities	227	(731)	(188)
Cash (used) provided by discontinued operations			
Operating activities	(13)	44	123
Investing activities	(21)	(46)	(126)
Financing activities	–	–	–
Net increase (decrease) in cash and cash equivalents	550	21	(19)
Cash and cash equivalents at beginning of year	56	35	54
Cash and cash equivalents at end of year	$606	$56	$35
Supplemental disclosures of cash flow information			
Cash paid during the year – interest (net of amount capitalized)	$644	$657	$643
– income taxes (net of refunds)	$168	$189	$177

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned Restricted Shares	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2002	238	$4,951	$(21)	$(102)	$(238)	$2,087	$6,677
Net income		–	–	–	–	782	782
Other comprehensive income		–	–	–	188	–	188
Comprehensive income							970
Issuance of shares	8	305	–	–	–	–	305
Stock options exercised		4	–	–	–	–	4
Purchase of restricted stock		(1)	(7)	–	–	–	(8)
Restricted stock expense recognition		–	10	–	–	–	10
Cancellation of restricted shares		(1)	1	–	–	–	–
Allocation of ESOP shares		12	–	13	–	–	25
Dividends ($2.26 per share)		–	–	–	–	(539)	(539)
Balance, December 31, 2003	246	5,270	(17)	(89)	(50)	2,330	7,444
Net income		–	–	–	–	759	759
Other comprehensive loss		–	–	–	(114)	–	(114)
Comprehensive income							645
Issuance of shares	1	62	–	–	–	–	62
Stock options exercised		18	–	–	–	–	18
Purchase of restricted stock		–	(7)	–	–	–	(7)
Restricted stock expense recognition		–	7	–	–	–	7
Cancellation of restricted shares		(4)	4	–	–	–	–
Allocation of ESOP shares		14	–	13	–	–	27
Dividends ($2.32 per share)		–	–	–	–	(563)	(563)
Balance, December 31, 2004	247	5,360	(13)	(76)	(164)	2,526	7,633
Net income		–	–	–	–	697	697
Other comprehensive income		–	–	–	60	–	60
Comprehensive income							757
Issuance of shares	5	199	–	–	–	–	199
Presentation reclassification – SFAS 123R adoption		(13)	13	–	–	–	–
Stock options exercised		8	–	–	–	–	8
Purchase of restricted stock		(8)	–	–	–	–	(8)
Restricted stock expense recognition		3	–	–	–	–	3
Allocation of ESOP shares		12	–	13	–	–	25
Stock-based compensation expense		10	–	–	–	–	10
Dividends ($2.38 per share)		–	–	–	–	(589)	(589)
Balance, December 31, 2005	252	$5,571	$ –	$(63)	$(104)	$2,634	$8,038

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	2005	2004	2003
Net income	$697	$759	$782
Other comprehensive income (loss)			
Reclassification adjustment for amounts included in net income:			
Change in cash flow hedges (net of tax expense of $26, $16 and $11, respectively)	46	26	19
Foreign currency translation adjustments included in discontinued operations	(6)	–	–
Minimum pension liability adjustment included in discontinued operations (net of tax expense of $1)	1	–	–
Changes in net unrealized losses on cash flow hedges (net of tax (expense) benefit of ($26), $10 and $7, respectively)	37	(18)	(12)
Reclassification of minimum pension liability to regulatory assets (net of tax expense of $2)	–	4	–
Minimum pension liability adjustment (net of tax benefit (expense) of $22, $78 and ($112), respectively)	(19)	(130)	177
Foreign currency translation and other (net of tax expense of $1, $- and $-, respectively)	1	4	4
Other comprehensive income (loss)	60	(114)	188
Comprehensive income	$757	$645	$970

See Notes to Consolidated Financial Statements.

In this report, Progress Energy [which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis] is at times referred to as "we," "us" or "our." Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF), as the "Utilities."

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

The Parent is a holding company headquartered in Raleigh, N.C. Prior to February 8, 2006, the Parent was registered under the Public Utility Holding Company Act of 1935 (PUHCA), as amended. As such, we were subject to the regulatory provisions of PUHCA. Subsequent to February 8, 2006, the Parent is subject to additional regulation by the Federal Energy Regulatory Commission (FERC) as a result of legislation passed in 2005.

Our reportable segments are: PEC, PEF, Progress Ventures, and Coal and Synthetic Fuels. Our PEC and PEF segments are engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. Our Progress Ventures segment is involved in nonregulated electric generation and energy marketing activities and natural gas drilling and production. Our Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuel as defined under the Internal Revenue Code (the Code), coal terminal services, and fuel transportation and delivery. Through our other business units, we engage in other nonregulated business areas, including telecommunications, which are included in our Corporate and Other segment (Corporate and Other).

Our Rail Services operations were reclassified to discontinued operations in the first quarter of 2005 (See Note 3B). During the fourth quarter of 2005, our coal mining operations were reclassified to discontinued operations (See Note 3A). Our Rail Services and coal mining operations are not included in the results from continuing operations during the periods reported.

During 2005, we realigned our segments based on the manner in which management currently reviews these operations. Prior year periods have been restated for our segment realignments. See Note 20 for further information about our segments.

B. Basis of Presentation

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over 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), are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 21). Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 13 for more information about our investments.

Diversified business revenues and expenses represent the operating activities of our consolidated nonregulated operations, which are primarily comprised of the Progress Ventures and Coal and Synthetic Fuels segments. These operations are separate and distinct businesses from the Utilities.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

These notes accompany and form an integral part of our consolidated financial statements.

Certain amounts for 2004 and 2003 have been reclassified to conform to the 2005 presentation.

C. Consolidation of Variable Interest Entities

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities for which we are the primary beneficiary in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46R, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51" (FIN No. 46R).

We have interests through other subsidiaries in variable interest entities for which we are not the primary beneficiary. These arrangements include investments in five limited liability partnerships and limited liability corporations. At December 31, 2005, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was approximately $8 million, which represents our net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to our general credit in excess of the aggregate maximum loss exposure.

PEC is the primary beneficiary of and consolidates two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Code. At December 31, 2005, the total assets of the two entities were $38 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC and PEC has applied the information scope exception in FIN No. 46R, paragraph 4(g), to the 17 partnerships. PEC has no direct exposure to loss from the 17 partnerships; PEC's only exposure to loss is from its investment of less than $1 million in the consolidated limited partnership. PEC will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to the 17 partnerships. We believe that if the limited partnership is determined to be the primary beneficiary of the 17 partnerships, the effect of consolidating the 17 partnerships would not be significant to our Consolidated Balance Sheets.

PEC also has an interest in one power plant resulting from long-term power purchase contracts. Our only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were approximately $44 million, $42 million and $37 million in 2005, 2004 and 2003, respectively. The generation capacity of the entity's power plant is approximately 835 MW. PEC has requested the necessary information to determine if the power plant owner is a variable interest entity or to identify the primary beneficiary. The entity declined to provide us with the necessary financial information and PEC has applied the information scope exception in FIN No. 46R, paragraph 4(g), to the power plant. We believe that if PEC is determined to be the primary beneficiary of the entity, the effect of consolidating the entity would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on our common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparty, the impact cannot be determined at this time.

PEC also has interests in several other variable interest entities for which PEC is not the primary beneficiary. These arrangements include investments in approximately 22 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2005, the aggregate maximum loss exposure that PEC could be required to record in its income statement as a result of these arrangements totals approximately $23 million, which primarily represents our net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to the general credit of PEC in excess of the aggregate maximum loss exposure.

PEF has interests in three variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one limited liability corporation, one venture capital fund and one building lease with a special-purpose entity. At December 31, 2005, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was approximately $1 million. The creditors of these variable interest entities do not have recourse to the general credit of PEF in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

...TES AND ASSUMPTIONS

In preparing consolidated financial statements that conform to GAAP, management must make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

...GNITION

We recognize revenue when it is realized or realizable and earned when all of the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; our price to the buyer is fixed or determinable; and collectability is reasonably assured. We recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility revenues earned when service has been delivered but not billed by the end of the accounting period. Diversified business revenues are generally recognized at the time products are shipped or as services are rendered. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Revenues related to design and construction of wireless infrastructure are recognized upon completion of services for each completed phase of design and construction. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

...ERRALS

Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by the Utilities' regulators. These clauses allow the Utilities to recover fuel costs and portions of purchased power costs through surcharges on customer rates. These deferred fuel costs are recognized in revenues and fuel expenses as they are billable to customers.

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in electric operating revenues and taxes other than on income in the statements of income were $258 million, $240 million and $217 million, respectively, for the years ended December 31, 2005, 2004 and 2003.

STOCK-BASED COMPENSATION

Prior to July 2005, we accounted for stock-based compensation under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25), and related interpretations in accounting for our stock-based compensation costs. In addition, we followed the disclosure requirements contained in SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123), as amended by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure" (SFAS No. 148). Effective July 1, 2005, we adopted the fair value recognition provisions of SFAS No. 123R, "Accounting for Stock-Based Compensation" (SFAS No. 123R), for stock-based compensation utilizing the modified prospective transition method (See Note 10B).

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the PUHCA. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. In the subsidiaries' financial statements, billings from affiliates are capitalized or expensed depending on the nature of the services rendered. The repeal of PUHCA effective February 8, 2006, and subsequent regulation by the FERC is not anticipated to change our current intercompany services.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs that would otherwise not be capitalized under GAAP are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), are charged to a regulatory liability.

Allowance for funds used during construction (AFUDC) represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform system of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income and the borrowed funds portion is credited to interest charges.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, we adopted the guidance in SFAS No. 143 to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. As discussed in Note 2, effective December 31, 2005, we also adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), which clarified certain requirements of SFAS No. 143.

The adoption of SFAS No. 143 and FIN 47 had no impact on the income of the Utilities as the effects were offset by the establishment of regulatory assets and regulatory liabilities pursuant to SFAS No. 71 (See Note 7A) and in accordance with orders issued by the NCUC, the SCPSC and the FPSC.

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

For financial reporting purposes, substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 7).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC, the SCPSC and the FPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdictions, the provisions for nuclear decommissioning costs are approved by the FERC.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with a maturity of three months or less.

INVENTORY

We account for inventory, including emission allowances, using the average cost method. Inventories are valued at the lower of average cost or market.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to SFAS No. 71, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

DIVERSIFIED BUSINESS PROPERTY

Diversified business property is stated at cost less accumulated depreciation. If an impairment is recognized on an asset, the fair value becomes its new cost basis. The costs of renewals and betterments are capitalized. The cost of repairs and maintenance is charged to expense as incurred. For properties other than oil and gas properties, depreciation is computed on a straight-line basis using the estimated useful lives disclosed in Note 5B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

We use the full-cost method to account for our oil and gas properties. Under the full-cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized.

These capitalized costs include the costs of all unproved properties and internal costs directly related to acquisition and exploration activities. The amortization base also includes the estimated future cost to develop proved reserves. Except for costs of unproved properties and major development projects in progress, all costs are amortized using the units-of-production method on a country-by-country basis over the life of our proved reserves. Accordingly, all property acquisition, exploration, and development costs of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized as incurred, including internal costs directly attributable to such activities. Related interest expense incurred during property development activities is capitalized as a cost of such activity. Net capitalized costs of unproved property are reclassified as proved property and well costs when related proved reserves are found. Costs to operate and maintain wells and field equipment are expensed as incurred. In accordance with Rule 4-10 of Regulation S-X, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless certain significance tests are met.

GOODWILL AND INTANGIBLE ASSETS

Goodwill is subject to at least an annual assessment for impairment by applying a two-step, fair value-based test. This assessment could result in periodic impairment charges. Intangible assets are being amortized based on the economic benefit of their respective lives.

AMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses are amortized over the terms of the debt issues. Any expenses or call premiums associated with the reacquisition of debt obligations by the Utilities are amortized over the applicable lives using the straight-line method consistent with ratemaking treatment (See Note 7A).

INCOME TAXES

We and our affiliates file a consolidated federal income tax return. Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuel are deferred as alternative minimum tax credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) in the Consolidated Statements of Income. Interest expense on tax deficiencies is included in net interest charges in the Consolidated Statements of Income.

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133" (SFAS No. 138), and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met. During 2003, the FASB reconsidered an interpretation of SFAS No. 133. See Note 18 for the effect of the interpretation and additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies, including uncertain tax benefits, in accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5). Under SFAS No. 5, contingent losses such as unfavorable results of litigation are recorded when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. Tax reserves are recorded for uncertain tax benefits when it is probable that the tax position will be disallowed and the amount of the disallowance can be reasonably estimated. Unless otherwise required by GAAP, we do not accrue legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 22, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

As discussed in Note 9, we account for impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). We review the recoverability of long-lived tangible and intangible assets whenever indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

We review our investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. We consider various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If we determine that an other-than-temporary decline exists in the value of its investments, it is our policy to write-down these investments to fair value.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) is not equal to or greater than total capitalized costs, we are required to write-down capitalized costs to this level. We perform this ceiling test calculation every quarter. No write-downs were required in 2005, 2004 or 2003.

SUBSIDIARY STOCK TRANSACTIONS

Gains and losses realized as a result of common stock sales by our subsidiaries are recorded in the Consolidated Statements of Income, except for any transactions that must be credited directly to equity in accordance with the provisions of Staff Accounting Bulletin No. 51, "Accounting for Sales of Stock by a Subsidiary."

2. NEW ACCOUNTING STANDARDS

See Note 10B for information regarding our third quarter 2005 implementation of SFAS No. 123R.

FASB EXPOSURE DRAFT ON ACCOUNTING FOR UNCERTAIN TAX POSITIONS, AN INTERPRETATION OF SFAS NO. 109, "ACCOUNTING FOR INCOME TAXES"

On July 14, 2005, the FASB issued an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), that would address the accounting for uncertain tax positions. The proposed interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the consolidated financial statements. We currently account for uncertain tax benefits in accordance with SFAS No. 5. Under SFAS No. 5, contingent losses are recorded when it is probable that the tax position will not be sustained and the amount of the disallowance can be reasonably estimated. During subsequent deliberations in November 2005, the FASB voted to tentatively adopt a more-likely-than-not criterion that the uncertain tax position will be sustained rather than the original probable criterion. As originally drafted, the proposed interpretation would apply to all uncertain tax positions and would have been effective for us on December 31, 2005. However, on January 11, 2006, the FASB voted to delay the effective date of the final interpretation until the first annual period beginning after December 15, 2006, which for us would be January 1, 2007. The FASB has publicly stated that it expects to issue the final interpretation in the first quarter of 2006. We have not yet determined how the proposed interpretation would impact our various income tax positions.

RETATION NO. 47, "ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS"

As discussed in Note 1D, we adopted FIN 47, an interpretation of SFAS No. 143, as of December 31, 2005. FIN 47 clarifies that a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of SFAS No. 143. Accordingly, an entity is required to recognize a liability for the fair value of an asset retirement obligation (ARO) that is conditional on a future event if the liability's fair value can be reasonably estimated. FIN 47 also provides additional guidance for evaluating whether sufficient information is available to make a reasonable estimate of the fair value.

Upon implementation of FIN 47 we recognized additional ARO liabilities for asbestos abatement costs. In accordance with SFAS No. 143, we recorded a liability for the present value of our legal obligations and recorded an additional amount to the asset cost to be depreciated over an appropriate period. Cumulative accretion and accumulated depreciation were recognized for the time period from the date of the obligating event giving rise to the liability to the date of the adoption of FIN 47. For assets acquired through acquisition, the cumulative effect was based on the acquisition date. As stated in Note 1D, the adoption of FIN 47 had no impact on the income of the Utilities as the effects were offset by the establishment of a net regulatory asset/liability pursuant to SFAS No. 71 (See Note 7A) and in accordance with orders issued by the NCUC, the SCPSC and the FPSC.

As of December 31, 2005, the effect of the implementation of FIN 47 on our financial statements was $50 million for ARO liability, $15 million for net asset retirement costs and $8 million for net regulatory liabilities.

Asbestos abatement costs previously included in regulatory liabilities were reclassified upon implementation of FIN 47 and included in the calculation of these AROs at December 31, 2005. The amounts reclassified were $16 million and $27 million for PEC and PEF, respectively, for a cumulative total of $43 million for Progress Energy.

3. DIVESTITURES

A. Coal Mines Divestiture

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels Corporation (Progress Fuels) engaged in the coal mining business. The coal mining operations are expected to be sold by the end of 2006. As a result, the accompanying consolidated financial statements have been restated for all periods presented to reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated was $3 million for each of the years ended December 31, 2005, 2004 and 2003. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the years ended December 31, 2005, 2004 and 2003 was $10 million, $9 million and $9 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2005	2004	2003
Revenues	**$180**	$158	$181
Loss before income taxes	**$16**	$17	$18
Income tax benefit	**5**	12	7
Net loss from discontinued operations	**$11**	$5	$11

B. Progress Rail Divestiture

On March 24, 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail) to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Gross cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. Proceeds from the sale were used to reduce debt.

Based on the gross proceeds associated with the sale of $429 million, we recorded an estimated after-tax loss on disposal of $25 million during the year ended December 31, 2005.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Progress Rail as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of Progress Rail, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2005, 2004 and 2003 was $4 million, $16 million and $18 million, respectively. We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the years ended December 31, 2005, 2004 and 2003 was $3 million, $10 million and $9 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2005	2004	2003
Revenues	$358	$1,127	$847
Earnings before income taxes	$8	$50	$23
Income tax expense	3	21	9
Net earnings from discontinued operations	5	29	14
Estimated loss on disposal of discontinued operations, including income tax benefit of $15 in 2005	(25)	–	–
(Loss) earnings from discontinued operations	$(20)	$29	$14

In connection with the sale, Progress Fuels and Progress Energy provided guarantees and indemnifications of certain legal, tax and environmental matters to One Equity Partners, LLC. See Note 23C for a general discussion of guarantees. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods.

In February 2004, we sold the majority of the assets of Railcar Ltd., a subsidiary of Progress Rail, to The Andersons, Inc. for proceeds of approximately $82 million before transaction costs and taxes of approximately $13 million. In 2002, we had recognized pre-tax impairment of $59 million to write-down the assets to our estimated fair value less costs to sell. In July 2004, we sold the remaining assets, which had been classified as held for sale, to a third party for net proceeds of $6 million.

C. Net Assets of Discontinued Operations

Included in net assets of discontinued operations are the assets and liabilities of the coal mining operations and Progress Rail. The major balance sheet classes included in assets and liabilities of discontinued operations in the Consolidated Balance Sheet at December 31, 2005 and 2004 were as follows:

(in millions)	2005	2004
Accounts receivable	$12	$189
Inventory	6	181
Other current assets	4	19
Total property, plant and equipment, net	73	240
Total other assets	14	56
Assets of discontinued operations	$109	$685
Accounts payable	$9	$119
Other current liabilities	11	47
Long-term liabilities	20	20
Liabilities of discontinued operations	$40	$186

D. Divestiture of Winter Park Distribution Assets

As discussed in Note 7C, PEF sold certain electric distribution assets to Winter Park, Fla. (Winter Park), on June 1, 2005.

E. Sale of Natural Gas Assets

In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd. (Winchester Production), an indirectly wholly owned subsidiary of Progress Fuels, which is included in the Progress Ventures segment. Net proceeds of approximately $251 million were used to reduce debt. Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting, the pre-tax gain of $56 million was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. The pre-tax gain has been included in (gain)/loss on the sale of assets in the Consolidated Statements of Income.

F. Divestiture of Synthetic Fuel Partnership Interests

In two June 2004 transactions, Progress Fuels sold a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its synthetic fuel facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gain from the sales will be recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. In the event that the synthetic fuel tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuel tax credits, the amount of proceeds realized from the sale could be significantly impacted (See Note 23D).

G. Mesa Hydrocarbons, Inc., Divestiture

In October 2003, we sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels. Net proceeds were approximately $97 million. Because we utilize the full-cost method of accounting for our oil and gas operations, the pre-tax gain of approximately $18 million was applied to reduce the basis of our other U.S. oil and gas investments and will prospectively result in a reduction of the amortization rate applied to those investments as production occurs.

H. NCNG Divestiture

On September 30, 2003, we sold North Carolina Natural Gas Corporation (NCNG) and our equity investment in Eastern North Carolina Natural Gas Company (ENCNG) to Piedmont Natural Gas Company, Inc. Net proceeds from the sale of NCNG of approximately $443 million were used to reduce debt.

The consolidated financial statements have been restated for all periods presented for the discontinued operations of NCNG. The net income of these operations is reported as discontinued operations in the Consolidated Statements of Income. Interest expense of $10 million for the year ended December 31, 2003, has been allocated to discontinued operations based on the net assets of NCNG, assuming a uniform debt-to-equity ratio across our operations. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2004	2003
Revenues	$–	$284
Earnings before income taxes	$–	$6
Income tax expense	–	2
Net earnings from discontinued operations	–	4
Gain/(Loss) on disposal of discontinued operations, including applicable income tax benefit / (expense) of $6 and $1, respectively	6	(12)
Earnings (loss) from discontinued operations	$6	$(8)

NCNG did not have any discontinued operating results for the year ended December 31, 2005.

During 2004, we recorded an additional tax gain of approximately $6 million due to final tax adjustments related to the divestiture of NCNG.

The sale of ENCNG resulted in net proceeds of $7 million and a pre-tax loss of $2 million, which is included in other, net on the Consolidated Statements of Income for the year ended December 31, 2003.

the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005, 2004 or 2003.

B. Progress Telecommunications Corporation Transaction

In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc. (Caronet), both wholly owned subsidiaries of Progress Energy, and EPIK Communications, Inc. (EPIK), a wholly owned subsidiary of Odyssey Telecorp, Inc. (Odyssey), contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC (PT LLC), a subsidiary of PTC as a noncash activity that is not reflected on our consolidated statements of cash flows. Subsequently, the stock of Caronet was sold to an affiliate of Odyssey for $2 million in cash and Caronet became a wholly owned subsidiary of Odyssey. Following consummation of all the transactions described above, PTC held a 55 percent ownership interest in, and is the parent of, PT LLC. Odyssey held a combined 45 percent ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Consolidated Financial Statements since the transaction date.

The transaction was accounted for as a partial acquisition of EPIK through the issuance of the stock of a consolidated subsidiary. The contributions of PTC's and Caronet's net assets were recorded at their carrying values of approximately $31 million. EPIK's contribution was recorded at its estimated fair value of $22 million using the purchase method. No gain or loss was recognized on the transaction. The EPIK purchase price was initially allocated as follows: property and equipment – $27 million; other current assets – $9 million; current liabilities – $21 million; and goodwill – $7 million. During 2004, PT LLC developed a restructuring plan to exit pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2003.

See Note 25 for information on the recent agreement to sell our interest in PT LLC.

C. Acquisition of Natural Gas Reserves – 2003

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 Bcf from Republic Energy, Inc., and three other privately owned companies, all headquartered in Texas. The total cash purchase price for the transactions was $168 million. The pro forma results of operations reflecting the acquisition would not be materially different from the reported results of operations for the year ended December 31, 2003.

D. Acquisition of Wholesale Energy Contract

In May 2003, Progress Energy Ventures, Inc. (PVI) entered into a definitive agreement with Williams Energy Marketing and Trading, a subsidiary of The Williams Companies, Inc., to acquire a long-term full-requirements power supply agreement at fixed prices with Jackson Electric Membership Corporation (Jackson), located in Jefferson, Georgia. The agreement required a $188 million cash payment to Williams Energy Marketing and Trading in exchange for assignment of the Jackson supply agreement; the $188 million cash payment was recorded as an intangible asset and is being amortized based on the economic benefit of the contract (See Note 8). The power supply agreement terminates in 2015, with a first refusal right to extend for five years. The agreement includes the use of 640 MW of contracted Georgia System generation comprised of nuclear, coal, gas and pumped-storage hydro resources. PVI expects to supplement the acquired resources with open market purchases and with its own intermediate and peaking assets in Georgia to serve Jackson's forecasted 1,100 MW peak demand in 2005 growing to a forecasted 1,700 MW demand by 2015.

5. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

The balances of electric utility plant in service at December 31 are listed below, with a range of depreciable lives (in years) for each:

(in millions)	Depreciable Lives	**2005**	2004
Production plant	7-33	**$12,470**	$11,966
Transmission plant	30-75	**2,353**	2,282
Distribution plant	12-50	**7,015**	6,749
General plant and other	8-75	**1,102**	1,106
Utility plant in service		**$22,940**	$22,103

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 12C).

AFUDC represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.5%, 2.2% and 2.5% in 2005, 2004 and 2003, respectively. The depreciation provisions related to utility plant were $556 million, $463 million and $517 million in 2005, 2004 and 2003, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Notes 7 and 22) and Clean Smokestacks Act amortization (See Note 7B).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2005 and 2004 were $140 million and for the year ended December 31, 2003, was $143 million. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

During 2004, PEC met the requirements of both the NCUC and the SCPSC for the implementation of two depreciation studies that allowed the utility to reduce the rates used to calculate depreciation expense. The annual reduction in depreciation expense is approximately $82 million. The reduction is due primarily to extended lives at each of PEC's nuclear units. The reduced depreciation rates were effective January 1, 2004.

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study will decrease the rates used to calculate depreciation expense with a resulting decrease in annual depreciation expense of $26 million beginning in 2006 (See Note 7C).

B. Diversified Business Property

The balances of diversified business property at December 31 are listed below, with a range of depreciable lives for each:

(in millions)	2005	2004
Equipment (3-25 years)	$146	$129
Nonregulated generation plant and equipment (3-40 years)	1,330	1,302
Land and mineral rights	40	36
Buildings and plants (5-40 years)	70	70
Oil and gas properties (units-of-production)	493	334
Telecommunications equipment (5-20 years)	99	80
Rail equipment (3-20 years)	37	36
Marine equipment (3-35 years)	88	87
Computers, office equipment and software (3-10 years)	8	13
Construction work in progress	12	18
Accumulated depreciation	(443)	(332)
Diversified business property, net	$1,880	$1,773

Our nonregulated businesses capitalize interest costs under SFAS No. 34, "Capitalization of Interest Costs." During the years ended December 31, 2005, 2004 and 2003, respectively, we capitalized $4 million, $7 million and $20 million, respectively, of our interest cost of $656 million, $641 million and $634 million, respectively. Capitalized interest for 2005 and 2004 is related to the expansion of natural gas operations. Capitalized interest in 2003 is related to the expansion of the Progress Ventures nonregulated generation portfolio. Capitalized interest is included in diversified business property, net on the Consolidated Balance Sheets. Diversified business depreciation expense was $116 million for December 31, 2005 and 2004 and $91 million for December 31, 2003.

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 22B). PEC's and PEF's share of expenses for the jointly owned facilities is included in the appropriate expense category. The co-owner of Intercession City Unit P11 (P11) has exclusive rights to the output of the unit during the months of June through September. PEF has that right for the remainder of the year. PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December 31:

2005 *(in millions)* Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$518	$255	$1
PEC	Harris	83.83%	3,181	1,459	17
PEC	Brunswick	81.67%	1,614	921	23
PEC	Roxboro Unit 4	87.06%	355	153	10
PEF	Crystal River Unit 3	91.78%	808	493	48
PEF	Intercession City Unit P11	66.67%	24	4	–

2004 *(in millions)* Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$516	$249	$1
PEC	Harris	83.83%	3,185	1,387	13
PEC	Brunswick	81.67%	1,624	888	28
PEC	Roxboro Unit 4	87.06%	323	147	1
PEF	Crystal River Unit 3	91.78%	889	443	9
PEF	Intercession City Unit P11	66.67%	22	7	8

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris), which are not applicable to the joint owner's ownership interest in Harris.

D. Asset Retirement Obligations

At December 31, 2005 and 2004, the asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $168 million and $275 million, respectively. Funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $1.133 billion and $1.044 billion at December 31, 2005 and 2004, respectively. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

Our decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million in 2005, 2004 and 2003. Management believes that decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset retirement obligations, which are included in depreciation and amortization expense, were $168 million, $160 million and $158 million in 2005, 2004 and 2003, respectively.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plants costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 7A). At December 31, such costs consisted of:

(in millions)	2005	2004
Removal costs	**$1,316**	$1,606
Nonirradiated decommissioning costs	**132**	131
Dismantlement costs	**123**	144
Non-ARO cost of removal	**$1,571**	$1,881

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 23D1). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Unit No. 1, $444 million for Brunswick Unit No. 2, and $775 million for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. NRC operating licenses held by PEC currently expire in December 2014 and September 2016 for Brunswick Units No. 2 and No. 1, respectively. An application to extend these licenses 20 years was submitted in October 2004. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years is expected to be submitted in the fourth quarter of 2006. On April 19, 2004, the NRC announced that it renewed the operating license for Robinson for an additional 20 years through July 2030.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 23D). The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. An application to extend this license 20 years is expected to be submitted in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $36 million and $88 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail and wholesale accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of the Agreement and the new Base Rate Settlement continues that suspension.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. The new study called for an increase in the annual accrual of $10 million beginning in 2006. PEF's reserve for fossil plant dismantlement was approximately $145 million at December 31, 2005, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's existing Agreement. The Base Rate Settlement continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN 47, as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 2).

We have identified but not recognized AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by us. These easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The ARO is not estimable for such easements, as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

Our nonregulated AROs relate to the synthetic fuel operations and gas production of Progress Fuels. The related asset retirement costs, net of accumulated depreciation, totaled $10 million and $4 million at December 31, 2005 and 2004, respectively.

The following table shows the changes to the AROs during the years ended December 31. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels and asbestos abatement at the Utilities. Revisions to prior estimates of the regulated ARO related to PEC remeasuring the nuclear decommissioning costs of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years. Revisions to prior estimates of the PEF regulated ARO are related to the updated cost estimate for nuclear decommissioning described above.

(in millions)	Regulated	Nonregulated
Asset retirement obligations at January 1, 2004	$1,251	$5
Additions	–	1
Accretion expense	73	–
Revisions to prior estimates	(63)	(2)
Asset retirement obligations at December 31, 2004	1,261	4
Additions	**50**	**6**
Accretion expense	**65**	**–**
Revisions to prior estimates	**(137)**	**–**
Asset retirement obligations at December 31, 2005	**$1,239**	**$10**

The cumulative effect of initial adoption of SFAS No. 143 related to nonregulated operations was $1 million of income, which is included in cumulative effect of change in accounting principles, net of tax on the Consolidated Statements of Income for the year ended December 31, 2003.

E. Insurance

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.75 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under NEIL, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at each plant. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amount. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $30.7 million with respect to the primary coverage, $36.5 million with respect to the decontamination, decommissioning and excess property coverage, and $23 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $10.76 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from an insured nuclear incident exceed $300 million (currently available through commercial insurers), each company would be subject to pro rata assessments of up to $100.1 million for each reactor owned per occurrence. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $15 million per reactor owned.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.2 billion, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply. For nuclear liability claims arising out of terrorist acts, the primary level available through commercial insurers is now subject to an industry aggregate limit of $300 million. The second level of coverage obtained through the assessments discussed above would continue to apply to losses exceeding $300 million and would provide coverage in excess of any diminished primary limits due to terrorist acts.

The Utilities self-insure their transmission and distribution lines against loss due to storm damage and other natural disasters. PEF accrues $6 million annually to a storm damage reserve pursuant to a regulatory order and may defer losses in excess of the reserve (See Note 7A).

6. CURRENT ASSETS

A. Receivables

Income tax receivables and interest income receivables are not included in receivables. These amounts are included in prepayments and other current assets on the Consolidated Balance Sheet. At December 31 receivables were comprised of:

(in millions)	2005	2004
Trade accounts receivable	**$713**	$499
Unbilled accounts receivable	**282**	271
Notes receivable	**76**	97
Other receivables	**45**	23
Unbilled other receivables	**6**	28
Allowance for doubtful accounts receivable	**(19)**	(22)
Total receivables	**$1,103**	$896

B. Inventory

At December 31 inventory was comprised of:

(in millions)	2005	2004
Fuel for production	**$329**	$235
Inventory for sale	**61**	49
Materials and supplies	**441**	517
Emission allowances	**35**	21
Total current inventory	**$866**	$822

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits for Progress Energy of $44 million at December 31, 2005 and none at December 31, 2004.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits for Progress Energy of $14 million at December 31, 2005 and none at December 31, 2004.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the Utilities are subject to the provisions of SFAS No. 71. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of SFAS No. 71 may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, these factors could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

At December 31 the balances of regulatory assets (liabilities) were as follows:

(in millions)	2005	2004
Deferred fuel cost – current (Notes 7B and 7C)	$602	$229
Deferred fuel cost – long-term (Notes 7B and 7C)	31	107
Deferred impact of ARO (Note 1D)	281	305
Income taxes recoverable through future rates (Note 14)	81	84
Loss on reacquired debt (Note 1D)	50	53
Storm deferral (Notes 7B and 7C)	227	316
Postretirement benefits (Note 16B)	88	74
Other	96	125
Total long-term regulatory assets	854	1,064
Deferred energy conservation cost – current	(10)	(8)
Non-ARO cost of removal (Note 5D)	(1,571)	(1,881)
Deferred impact of ARO (Note 1D)	(225)	(221)
Net nuclear decommissioning trust unrealized gains (Note 5D)	(251)	(224)
Postretirement benefits (Note 16B)	–	(45)
Clean Smokestacks Act compliance (Note 7B)	(317)	(248)
Derivative mark-to-market adjustment (Note 18A)	(122)	(2)
Other	(41)	(33)
Total long-term regulatory liabilities	(2,527)	(2,654)
Net regulatory liabilities	$(1,081)	$(1,369)

Except for portions of deferred fuel costs, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We expect to fully recover these assets and refund these liabilities through customer rates under current regulatory practice.

B. PEC Retail Rate Matters

;OVERY

On April 27, 2005, PEC filed for an increase in the fuel rate charged to its South Carolina retail customers with the SCPSC. PEC requested the $99 million increase for under-recovered fuel costs for the previous 15 months and to meet future expected fuel costs. On June 23, 2005, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceeding. The settlement agreement levelizes the collection of under-recovered fuel costs over a three-year period and allows PEC to charge and recover carrying costs on the monthly unpaid balance, beginning July 1, 2006, at an interest rate of 6% compounded annually. An annual increase in PEC's rates of $55 million, or 12 percent, was effective July 1, 2005. Residential electric bills increased by $7.29 per 1,000 kWhs for fuel cost recovery. The South Carolina deferred fuel balance at December 31, 2005, was $38 million, of which $21 million will be collected after 2006 in accordance with the settlement agreement and therefore has been classified as a long-term regulatory asset.

On June 3, 2005, PEC filed for an increase in the fuel rate charged to its North Carolina retail customers with the NCUC. PEC requested that the NCUC approve an annual increase of $276 million, or 11 percent. PEC requested the increase for under-recovered fuel costs for the previous 12 months and to meet future expected fuel costs. On September 26, 2005, the NCUC approved a settlement agreement proposed by PEC and other parties to the proceeding. In the settlement, PEC will collect all of its fuel cost under-collections that occurred during the test year ended March 31, 2005, over a one-year period beginning October 1, 2005. PEC agreed to reduce its proposed billing increment, designed to collect future fuel costs, in order to address customer concerns regarding the magnitude of the proposed increase. The NCUC approved an annual increase of $133 million, an average increase of 5 percent. In recognition of the likely under-collection that will result during the year ending September 30, 2006, PEC is allowed to calculate and collect interest at 6% on the difference between its collection factor in the original request to the NCUC and the factor included in the settlement agreement until such amounts have been collected. Effective October 1, 2005, residential electric bills increased by $3.71 per 1,000 kilowatt-hours (kWhs) for fuel cost recovery. At December 31, 2005, PEC's North Carolina retail fuel costs were under-recovered by $254 million. This amount was comprised of $244 million eligible for recovery in 2006 and $10 million deferred from a 2001 NCUC order that cannot be collected until 2007 and therefore has been classified as a long-term regulatory asset.

In 2004 and 2003, PEC obtained SCPSC and NCUC approval of fuel factors in annual fuel-adjustment proceedings. The NCUC approved an annual increase of $62 million and $20 million, respectively, by orders issued in September 2004 and 2003. The SCPSC approved PEC's petition each year and the changes were insignificant.

STORM COST RECOVERY

In February 2004, PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. In September 2004, the SCPSC approved PEC's request to defer the costs and amortize them ratably over five years beginning in January 2005. Approximately $9 million related to storm costs was deferred in 2004. PEC recognized $2 million of South Carolina storm amortization during 2005.

In October 2003, PEC filed with the NCUC seeking permission to defer expenses incurred from Hurricane Isabel and the February 2003 winter storms. In December 2003, the NCUC approved PEC's request to defer the costs associated with Hurricane Isabel and the February 2003 winter storms and amortize them over a period of five years. PEC charged approximately $24 million in 2003 from Hurricane Isabel and from winter storms to the deferred account. PEC recognized $5 million, $5 million and $3 million of North Carolina storm amortization during 2005, 2004 and 2003, respectively.

OTHER MATTERS

The NCUC and SCPSC have approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 million, respectively. Accelerated cost recovery of these assets resulted in no additional expense in 2005, 2004 or 2003. Through December 31, 2005, PEC recorded total accelerated depreciation of $403 million.

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) enacted in June 2002 requires state utilities to reduce emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired plants. The law provides that the utilities shall amortize and recover the original estimated costs (subject to adjustment by the NCUC) associated with meeting the new emission standards over a seven-year period beginning January 1, 2003. The legislation provides for significant flexibility in the amount of annual amortization recorded, which allows the utilities to vary the amount amortized within certain limits. This flexibility provides a utility with the opportunity to consider the impacts of other factors on its regulatory return on equity (ROE) when setting the amortization amount for each year. PEC recognized $147 million, $174 million and $74 million of Clean Smokestacks Act amortization during 2005, 2004 and 2003, respectively. This legislation freezes PEC's base rates in North Carolina through December 31, 2007, subject to certain conditions (See Note 22B).

In conjunction with our acquisition of Florida Progress Corporation (Florida Progress), PEC reached a settlement with the Public Staff of the NCUC in which it agreed to provide $20 million of credits to its nonreal-time pricing customers including $6 million in both 2005 (the last year the agreed-upon credits were provided) and 2004 and $5 million in 2003.

C. PEF Retail Rate Matters

STORM COST RECOVERY

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. The ruling allowed PEF to include a charge of approximately $3.27 on the average residential monthly customer bill of 1,000 kWhs beginning August 1, 2005. The ruling by the FPSC approved the majority of PEF's requests with two exceptions: the reclassification of $8 million of previously deferred costs to utility plant and the reclassification of $17 million of previously deferred costs as normal operation and maintenance (O&M) expense, which was expensed in the second quarter of 2005. In 2005, PEF recorded approximately $50 million of amortization associated with the recovery of these storm costs.

The amount included in the original petition requesting recovery of $252 million in November 2004 was an estimate, as actual total costs were not known at that time. On September 12, 2005, PEF filed a true-up to the original amount requested. PEF incurred an additional $19 million in costs in excess of the amount requested in the original petition. This increase was partially offset by $6 million of adjustments due to allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments. On November 9, 2005, as part of the action taken by the FPSC on PEF's pass-through clause cost recovery discussed below, the recovery of this difference was administratively approved by the FPSC, subject to audit by the FPSC staff. The net impact was included in customer bills beginning January 1, 2006.

On June 1, 2005, the governor of Florida signed into law a bill that allows utilities to petition the FPSC to use securitized bonds to recover storm-related costs. PEF is reviewing whether it will seek FPSC approval to issue securitized debt to recover any outstanding balance of its 2004 storm costs and to replenish its storm reserve fund, or to continue the current replenishment of its storm reserve fund through base rates and a surcharge mechanism. If PEF seeks recovery through securitization and assuming FPSC approval, PEF expects the process to take six to nine months to complete.

PASS-THROUGH CLAUSE COST RECOVERY

On November 9, 2005, the FPSC approved PEF's filed request seeking a total increase of $605 million over 2005 to recover rising fuel costs as well as costs related to other pass-through clauses and surcharges. Fuel costs of

$560 million and certain purchased power costs of $42 million were the largest component of the total increase. The fuel cost increase includes $17 million from 2004 under-recoveries, $222 million from 2005 under-recoveries and a $321 million increase for 2006. Beginning January 1, 2006, residential electric bills increased by $11.78 per 1,000 kWhs each billing cycle through December 31, 2006. At December 31, 2005, PEF was under-recovered in fuel and capacity costs by $341 million.

To encourage energy conservation, the FPSC's ruling allows PEF to implement a two-tiered fuel rate for residential customers that charges a lower rate for the first 1,000 kWhs and a higher rate for each additional kWh.

BASE RATE SETTLEMENT

On April 29, 2005, PEF submitted minimum filing requirements, based on a 2006 projected test year, to initiate a base rate proceeding regarding its future base rates. In its filing, PEF requested a $206 million annual increase in base rates effective January 1, 2006. On September 7, 2005, the FPSC approved an agreement (Base Rate Settlement) that maintains PEF's base rates at their current level through late 2007, except as modified elsewhere in the Base Rate Settlement. The new base rates took effect the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009 with PEF having sole option to extend through the last billing cycle of June 2010.

Under the Base Rate Settlement, PEF will continue to collect a return on and depreciation of Hines Unit 2 through the fuel clause, as was permitted under the terms of the existing Stipulation and Settlement Agreement (the Agreement), through late 2007 when it will be transferred into base rates. This transfer will correspond with the in-service dates of the Hines Unit 4, which will also be recovered through a base rate increase. PEF began recovering the cost of its Hines Unit 3 through existing base rates when it was placed into service in November 2005, similar to other utility property additions.

The Base Rate Settlement authorizes PEF to recover certain costs through clauses, such as the continued recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause.

The Base Rate Settlement also provides for revenue sharing between PEF and its customers. In 2006, PEF will refund two-thirds of retail, base revenues between the $1.499 billion threshold and the $1.549 billion cap and 100 percent of revenues above the $1.549 billion cap. Both the threshold and cap will be adjusted annually for rolling average 10-year retail kWh sales growth.

The Base Rate Settlement authorizes PEF to include an adjustment to increase common equity for the impact of Standard & Poor's (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and pass-through clause return calculations. PEF will use an authorized 11.75 percent ROE for cost recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent. If PEF's regulatory ROE falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

The FPSC requires that PEF perform a depreciation study no less frequently than every four years. PEF filed a depreciation study for the FPSC's approval on April 29, 2005, as part of its base rate filing, which would increase depreciation expense by $14 million beginning in 2006. PEF reduced its estimated removal costs to take into account the estimates used in the depreciation study. This resulted in a downward revision in PEF's estimated removal costs, a component of regulatory liabilities, and an equal increase in accumulated depreciation of $401 million. On September 7, 2005, the FPSC approved a modification to the study that resulted in a decrease to the filed report of $40 million. Consequently, the impact of the rate changes in the depreciation study will decrease annual depreciation expense by $26 million beginning in 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. The new study called for an increase in the annual accrual of $10 million beginning in 2006. PEF's reserve for fossil plant dismantlement, including amounts in the ARO liability for asbestos abatement, was $145 million at December 31, 2005. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's existing Agreement. The Base Rate Settlement continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for CR3 with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning. The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. An application to extend this license 20 years is expected to be submitted in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its ARO liability by $88 million. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of the Agreement and the new Base Rate Settlement continues that suspension.

FRANCHISE MATTERS

On June 1, 2005, Winter Park acquired PEF's electric distribution system that serves Winter Park for approximately $42 million. On June 1, 2005, PEF transferred the distribution system to Winter Park and recognized a pre-tax gain of approximately $25 million on the transaction, which is included as an offset to other utility expense on the Statements of Income. This amount was decreased $1 million in the third quarter of 2005 upon accumulation of the final capital expenditures incurred since arbitration. PEF also recorded a regulatory liability of $8 million for stranded cost revenues, which will be amortized to revenues over six years in accordance with the provisions of the transfer agreement with Winter Park. In June 2004, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option.

OTHER MATTERS

On June 29, 2004, the FPSC approved a Stipulation and Settlement Agreement, executed on April 29, 2004, by PEF, the Office of Public Counsel and the Florida Industrial Power Users Group. The stipulation and settlement resolved the issue pending before the FPSC regarding the costs PEF will be allowed to recover through its Fuel and Purchased Power Cost Recovery clause in 2004 and beyond for waterborne coal deliveries by PEF's affiliated coal supplier, Progress Fuels. The settlement sets fixed per ton prices based on point of origin for all waterborne coal deliveries in 2004, and establishes a market-based pricing methodology for determining recoverable waterborne coal transportation costs through a competitive solicitation process or market price proxies in 2005 and thereafter. The settlement reduces the amount that PEF will charge to the Fuel and Purchased Power Cost Recovery clause for waterborne transportation by approximately $11 million beginning in 2004.

On November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex. Hines Unit 4 is needed to maintain electric system reliability and integrity and to continue to provide adequate electricity to its ratepayers at a reasonable cost. Hines Unit 4 will be a combined cycle unit with a generating capacity of 461 MW (summer rating). The estimated total in-service cost of Hines Unit 4 is $286 million, and the unit is planned for commercial operation in December 2007. If the actual cost is less than the estimate, customers will receive the benefit of such cost under-runs. Any costs that exceed this estimate will not be recoverable absent extraordinary circumstances as found by the FPSC in subsequent proceedings.

D. Regional Transmission Organizations

In 2000, the FERC issued Order No. 2000 regarding regional transmission organizations (RTOs). This Order set minimum characteristics and functions that RTOs must meet, including independent transmission service. In October 2000, as a result of Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of an RTO, GridSouth. In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the southeastern United States engage in mediation to develop a plan for a single RTO. PEC participated in the mediation. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding. PEC has $33 million invested in GridSouth related to startup costs at December 31, 2005. PEC expects to recover these startup costs.

The FPSC ruled in December 2001 that the formation of GridFlorida by the three major investor-owned utilities in Florida, including PEF, was prudent but ordered changes in the structure and market design of the proposed organization. In September 2002, the FPSC set a hearing for market design issues; this order was appealed to the Florida Supreme Court by the consumer advocate of the state of Florida. In June 2003, the Florida Supreme Court dismissed the appeal without prejudice. In September 2003, the FERC held a Joint Technical Conference with the FPSC to consider issues related to formation of an RTO for peninsular Florida. In December 2003, the FPSC ordered further state proceedings and established a collaborative workshop process to be conducted during 2004. In June 2004, the workshop process was abated pending completion of a cost-benefit study. On December 12, 2005, the final report of the cost-benefit study was issued. The study concluded that the GridFlorida RTO was not cost effective. The study further segregated the costs and benefits between FPSC jurisdictional and nonjurisdictional customers, concluding that the jurisdictional customers would incur even more costs and benefits would be shifted to nonjurisdictional customers. In light of the findings and conclusions of the cost-benefit study, on January 27, 2006, the GridFlorida applicants filed a motion to withdraw the compliance filing and filed a petition to close the docketed proceeding. The Florida Municipal Power Agency and Seminole Electric Power Cooperative have submitted a filing in opposition to this motion. The FPSC has released a schedule that indicates that they will issue an order on this motion by April 24, 2006. The GridFlorida applicants are currently in discussions to determine whether there are cost-effective alternatives to the GridFlorida proposal that could be implemented in peninsular Florida. PEF has fully recovered its startup costs in GridFlorida from retail ratepayers.

E. FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market-based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. PEF does not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believed it would experience in passing one of the interim screens, on September 6, 2005, PEC filed revisions to its market-based rate tariffs restricting them to sales outside PEC's control area and peninsular Florida and a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs.

F. Energy Delivery Capitalization Practice

We reviewed our capitalization policies for the Utilities' distribution operations (Energy Delivery) in 2004. That review indicated that in the areas of outage and emergency work not associated with major storms and allocation of indirect costs, both PEC and PEF should revise the way that they estimate the amount of capital costs associated with such work. Effective January 1, 2005, we implemented changes that included more detailed classification of outage and emergency work resulting in more precise estimation and implemented a process to retest accounting estimates on an annual basis. As a result of the changes in accounting estimates for the outage and emergency work and indirect costs, a lesser proportion of PEC's and PEF's costs will be capitalized on a prospective basis. The combined impact for the Utilities in 2005 was to expense approximately $63 million of costs that would have been capitalized under the previous policies. Of this total, $26 million related to PEC and $37 million related to PEF. Pursuant to SFAS No. 71, the Utilities informed the state regulators having jurisdiction over them of this change and that the new estimation process was implemented effective January 1, 2005. We also requested and received a method change from the Internal Revenue Service (IRS) during 2005.

8. GOODWILL AND OTHER INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill impairment was tested for both the PEC and PEF segments in the second quarters of 2004 and 2005; each test indicated no impairment.

For our Progress Ventures segment, the goodwill impairment tests are performed at the reporting unit level of our Effingham, Monroe, Walton and Washington nonregulated generation plants (Georgia Region), which is one level below the Progress Ventures segment. We performed the annual goodwill impairment test for our Georgia Region reporting unit in the first quarters of 2005 and 2004, each of which indicated no impairment. In response to changing gas and electricity prices that have a significant impact on the future cash flows of our Georgia Region operations, we also performed an interim goodwill impairment test for the Progress Ventures goodwill in the third and fourth quarters of 2005, each of which indicated no impairment. However, as part of our evaluation of certain business opportunities in the first quarter of 2006, we performed an interim impairment test for the $64 million of goodwill, which indicated the fair value of the Georgia Region was less than its carrying value. As required by SFAS No. 142, we are currently performing the second step of the impairment test, which compares the implied fair value of the goodwill with the recorded goodwill. While the results of the second step of the impairment test are currently unknown, the effects could range from no change to the recorded goodwill value to a potential write-off of $64 million.

Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination. The changes in the carrying amount of goodwill, by reportable segment for the years ended December 31 were as follows:

(in millions)	PEC	PEF	Progress Ventures	Corporate and Other	Total
Balance at January 1, 2003	$1,922	$1,733	$64	$–	$3,719
Acquisitions	–	–	–	7	7
Balance at December 31, 2003	1,922	1,733	64	7	3,726
Purchase accounting adjustment	–	–	–	(7)	(7)
Balance at December 31, 2004	1,922	1,733	64	–	3,719
Balance at December 31, 2005	**$1,922**	**$1,733**	**$64**	**$–**	**$3,719**

In December 2003, $7 million in goodwill was recorded based on a preliminary purchase price allocation as part of the PTC partial acquisition of EPIK and was reported in the Corporate and Other segment. As discussed in Note 4B, we revised the preliminary EPIK purchase price allocation as of September 2004, and the $7 million of goodwill was reallocated to certain tangible assets acquired based on the results of valuations and appraisals.

The gross carrying amount and accumulated amortization of the intangible assets at December 31 were as follows:

	2005		2004	
(in millions)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Synthetic fuel intangibles	$134	$(98)	$134	$(80)
Power agreements acquired	188	(19)	188	(6)
Other	112	(15)	111	(11)
Total	$434	$(132)	$433	$(97)

In June 2004, we sold, in two transactions, a combined 49.8 percent partnership interest in Colona, one of our synthetic fuel operations. Approximately $6 million in synthetic fuel intangibles and $3 million in related accumulated amortization were included in the sale of the partnership interest.

All of our intangibles, except minimum pension liability adjustments, are subject to amortization. Synthetic fuel intangibles represent intangibles for synthetic fuel technology. These intangibles are being amortized on a straight-line basis until the expiration of tax credits under Section 29/45K in December 2007 (See Note 23D). The intangibles related to power agreements acquired are being amortized based on the economic benefits of the contracts (See Note 4D). Other intangibles are primarily acquired customer contracts, permits that are amortized over their respective lives and minimum pension liability adjustments.

Amortization expense recorded on intangible assets for the years ended December 31, 2005, 2004 and 2003 was $35 million, $42 million and $36 million, respectively. The estimated annual amortization expense for intangible assets for 2006 through 2010 is approximately $36 million, $37 million, $18 million, $18 million and $19 million, respectively.

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2005 and 2003, we recorded pre-tax long-lived asset and investment impairments and other charges of $1 million and $38 million, respectively. No impairments were recorded in 2004.

A. Long-Lived Assets

Due to the reduction in coal production, we evaluated Kentucky May coal mine's long-lived assets in 2003. Fair value was determined based on discounted cash flows. As a result of this review, we recorded asset impairments of $17 million on a pre-tax basis during the fourth quarter of 2003. As discussed in Note 3A, all amounts directly related to the coal mines are included in discontinued operations on the Consolidated Statements of Income. Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuel plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded. See Note 23D for additional information.

B. Investments

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and Emerging Issues Task Force (EITF) Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (EITF 03-1). Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in impairments of investments. See Note 13 for additional information.

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. As a result of various factors including continued operating losses of the AHI portfolio and management issues arising at certain properties within the AHI portfolio, we recorded impairment charges of $1 million and $18 million on a pre-tax basis in 2005 and 2003, respectively. PEC also recorded an impairment of $3 million for a cost investment in 2003. No impairments were recorded in 2004.

10. EQUITY

A. Common Stock

At December 31, 2005 and 2004, we had 500 million shares of common stock authorized under our charter, of which 252 million shares and 247 million shares, respectively, were outstanding. At December 31, 2005 and 2004, we had approximately 58 million shares and 63 million shares, respectively, of common stock authorized by the board of directors that remained unissued and reserved, primarily to satisfy the requirements of our stock plans. In 2002, the board of directors authorized meeting the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan with original issue shares. During 2005, 2004 and 2003, respectively, we issued approximately 4.6 million, 1.4 million and 7.5 million shares, respectively, under these plans for net proceeds of approximately $199 million, $62 million and $305 million, respectively. We continue to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2005, there were no significant restrictions on the use of retained earnings (See Note 12).

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. Participating subsidiaries as of January 1, 2003, were PEC, PEF, PTC, PVI, Progress Fuels (corporate employees) and Progress Energy Service Company, LLC (PESC). Effective December 19, 2003, (the PT LLC/EPIK merger date), PTC no longer participates in the 401(k). The 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. To the extent used to repay such loans, the dividends are deductible for income tax purposes. Also, beginning in 2002, the dividends paid on ESOP shares that are either paid directly to participants or used to purchase additional shares which are subsequently allocated to participants, are fully deductible for income tax purposes.

There were 2.9 million and 3.5 million ESOP suspense shares at December 31, 2005 and 2004, respectively, with a fair value of $126 million and $156 million, respectively. ESOP shares allocated to plan participants totaled 11.4 million and 12.6 million at December 31, 2005 and 2004, respectively. Our matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year, while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $18 million, $21 million and $20 million for the years ended December 31, 2005, 2004 and 2003, respectively. Total matching and incentive costs totaled approximately $30 million, $32 million and $35 million for the years ended December 31, 2005, 2004 and 2003, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

NEW ACCOUNTING FOR STOCK-BASED COMPENSATION

In December 2004, the FASB issued SFAS No. 123R, which revises SFAS No. 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB Opinion No. 25). The key requirement of SFAS No. 123R is that the cost of stock-based awards to employees will be measured based on an award's fair value at the grant date, with such cost to be amortized over the appropriate service period, net of estimated forfeitures. Previously, entities could elect to continue accounting for such awards at their grant date intrinsic value under APB Opinion No. 25, and we made that election. The intrinsic value method resulted in our recording no compensation expense for stock options granted to employees. Also, as previously allowed, we recognized the expense effects of forfeitures as they occurred. SFAS No. 123R also changes prospectively the presentation of certain stock-based compensation excess income tax benefits in the statement of cash flows, with such excess tax benefits shown as financing cash inflows rather than operating cash inflows.

We adopted SFAS No. 123R as of July 1, 2005, using the required modified prospective method. Under that method, we will record compensation expense under SFAS No. 123R for all awards granted after July 1, 2005, and will record compensation expense (as previous awards continue to vest) for the unvested portion of previously granted awards that were outstanding at July 1, 2005. For awards with graded-vesting features, we will recognize expense using the grading-vesting method alternative in SFAS No. 123R. As a result of the adoption of SFAS No. 123R, on a prospective basis, we will not show unearned restricted shares as a negative component of common stock equity; rather, such amounts will be included in the determination of common stock presented in the Consolidated Balance Sheets. In addition, on a prospective basis, for new awards that effectively vest upon an employee's retirement eligibility, we will recognize expense over a vesting period based on the effective vesting date. Previously, we recognized expense over a vesting period based on the stated vesting date.

Adoption of SFAS No. 123R resulted in our recognizing approximately $3 million of pre-tax expense for stock options during the year ended December 31, 2005, which would not have been recognized under the prior accounting treatment. We curtailed our stock option program in 2004 and replaced that compensation program with other programs. Therefore, the amount of stock option expense recorded in 2005 is below the amount that would have been recorded if the stock option program had continued. Additionally, we recognized a cumulative pre-tax benefit from the accounting change of approximately $1 million, which reflects the cumulative impact of estimating forfeitures in the determination of period expense for other stock-based compensation plans, rather than recording the effect of forfeitures as they occur. As a result of the adoption of SFAS No. 123R, on a prospective basis we will not show unearned restricted shares as a negative component of common stock equity; rather, such amounts will be included in the determination of common stock presented in the Consolidated Balance Sheets. The adoption of SFAS No. 123R did not have a material impact on our income, earnings per share or our presentation of cash flows for the year ended December 31, 2005.

STOCK OPTIONS

Pursuant to our 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, we may grant options to purchase shares of our common stock to directors, officers and eligible employees (up to 15 million shares). Generally, options granted to employees vest one-third per year with 100 percent vesting at the end of year three, while options granted to directors vest 100 percent at the end of one year. The options expire 10 years from the date of grant. All option grants have an exercise price equal to the fair market value of our common stock on the grant date. As noted above, we have ceased granting stock options. An immaterial number of stock options were granted in 2004 and no stock options have been granted in 2005. We issue new shares of common stock to satisfy the exercise of previously issued stock options.

A summary of the status of our stock options at December 31, 2005, and changes during the year then ended, is presented below:

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	7.4	$43.57
Granted	–	–
Forfeited	(0.1)	$44.12
Canceled	(0.1)	$43.75
Exercised	(0.2)	$42.70
Options outstanding, December 31	7.0	$43.58
Options exercisable, December 31	6.0	$43.40

The options outstanding at December 31, 2005, had a weighted-average remaining contractual life of 6.6 years and an aggregate intrinsic value of $5 million. The options exercisable at December 31, 2005, had a weighted-average remaining contractual life of 6.4 years and an aggregate intrinsic value of $5 million.

The total intrinsic value of options exercised during the year ended December 31, 2004, was $1 million. Total intrinsic value of options exercised during the years ended December 31, 2005 and 2003, was less than $1 million in each year.

Compensation cost, for pro forma purposes prior to the adoption of SFAS No. 123R and for expense purposes subsequent to the adoption, is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions:

	2004	2003
Risk-free interest rate	4.22%	4.25%
Dividend yield	5.19%	4.75%
Volatility factor	20.30%	22.28%
Weighted-average expected life of the options (in years)	10	10

Dividend yield and the volatility factor were calculated using three years of historical trend information. The expected term was based on the contractual life of the options.

Stock option expense totaling $3 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income and earnings per share if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions except per share data)	2005	2004	2003
Net income, as reported	$697	$759	$782
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2	10	11
Pro forma net income	$695	$749	$771
Earnings per share			
Basic – as reported	$2.82	$3.13	$3.30
Basic – pro forma	2.81	3.09	3.25
Diluted – as reported	2.82	3.12	3.28
Diluted – pro forma	2.81	3.08	3.24

At December 31, 2005, there was $2 million of total unrecognized compensation cost related to nonvested stock options that will be recognized over one year.

Cash received from the exercise of stock options totaled $8 million, $18 million and $4 million, respectively, during the years ended December 31, 2005, 2004 and 2003. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2005, 2004 and 2003 was not significant.

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. The two primary active stock-based compensation programs are the Performance Share Sub-Plan (PSSP) and the Restricted Stock Awards (RSA) program, both of which were established pursuant to our 1997 Equity Incentive Plan and were continued under our 2002 Equity Incentive Plan, as amended and restated as of July 10, 2002.

We granted cash-settled PSSP awards prior to 2005. Beginning in 2005, we are granting stock-settled PSSP awards. Under the terms of the cash-settled PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. The PSSP has two equally weighted performance measures, both of which are based on our results as compared to a peer group of utilities. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. Compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with certain subsequent adjustments related to our results as compared to the peer group of utilities. PSSP cash-settled liabilities totaling $5 million, $7 million and $6 million were paid in the years ended December 31, 2005, 2004 and 2003, respectively. In 2005, we granted 540,588 stock-settled performance shares having a weighted-average grant date fair value of $44.24, with no forfeitures as of December 31, 2005.

The RSA program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2005, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	645,176	$42.32
Granted	192,800	42.56
Vested	(149,934)	38.75
Forfeited	(99,734)	42.53
Ending balance	588,308	$43.27

The weighted-average grant date fair value of restricted stock granted during the years ended December 31, 2004 and 2003, was $46.95 and $39.53, respectively.

The total fair value of restricted stock vested during the years ended December 31, 2005, 2004 and 2003 was $7 million, $16 million and $6 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million, $7 million and $7 million during the years ended December 31, 2005, 2004 and 2003, respectively.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $10 million for the year ended December 31, 2005, with a recognized tax benefit of $4 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $10 million for the year ended December 31, 2004, with a recognized tax benefit of $4 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $27 million for the year ended December 31, 2003, with a recognized tax benefit of $10 million. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2005, there was $34 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 2.2 years.

C. Earnings Per Common Share

Basic earnings per common share is based on the weighted-average number of common shares outstanding. Diluted earnings per share includes the effect of the nonvested portion of restricted stock awards and the effect of stock options outstanding.

A reconciliation of the weighted-average number of common shares outstanding for the years ended December 31 for basic and dilutive purposes follows:

(in millions)	2005	2004	2003
Weighted-average common shares – basic	**246.6**	242.2	237.2
Restricted stock awards	**.3**	.8	1.0
Stock options	**.1**	.1	–
Weighted-average shares – fully diluted	**247.0**	243.1	238.2

There are no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average shares totaled 3.0 million, 3.6 million and 4.1 million for the years ended December 31, 2005, 2004 and 2003, respectively. There were 2.9 million, 3.0 million and 5.3 million stock options outstanding at December 31, 2005, 2004 and 2003, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss, net of tax, at December 31 were as follows:

(in millions)	2005	2004
Gain (loss) on cash flow hedges	**$55**	$(28)
Minimum pension liability adjustments	**(160)**	(142)
Foreign currency translation and other	**1**	6
Total accumulated other comprehensive loss	**$(104)**	$(164)

11. PREFERRED STOCK OF SUBSIDIARIES – NOT SUBJECT TO MANDATORY REDEMPTION

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2005 and 2004, preferred stock outstanding consisted of the following:

	Shares		Redemption	
(dollars in millions, except share and per share data)	Authorized	Outstanding	Price	Total
PEC				
Cumulative, no par value $5 Preferred Stock	300,000			
$5 Preferred		236,997	$110.00	$24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	–	–	–
No par value Preference Stock	10,000,000	–	–	–
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	$104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	–	–	–
$100 par value Preference Stock	1,000,000	–	–	–
Total PEF				34
Total preferred stock of subsidiaries				$93

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2005):

(in millions)		2005	2004
Progress Energy, Inc.			
Senior unsecured notes, maturing 2006-2031	6.78%	**$4,300**	$4,300
Draws on revolving credit agreement, expiring 2009		**–**	160
Unamortized fair value hedge gain, net		**(3)**	12
Unamortized premium and discount, net		**(19)**	(23)
Current portion of long-term debt		**(404)**	–
Long-term debt, net		**3,874**	4,449
PEC			
First mortgage bonds, maturing 2006-2033	5.76%	**2,200**	1,600
Pollution control obligations, maturing 2017-2024	3.21%	**669**	669
Unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes, maturing 2008	6.65%	**300**	300
Miscellaneous notes		**22**	–
Unamortized premium and discount, net		**(24)**	(19)
Current portion of long-term debt		**–**	(300)
Long-term debt, net		**3,667**	2,750
PEF			
First mortgage bonds, maturing 2008-2033	5.39%	**1,630**	1,330
Pollution control obligations, maturing 2018-2027	3.07%	**241**	241
Senior unsecured notes, maturing 2008	4.88%	**450**	–
Medium-term notes, maturing 2006-2028	6.77%	**289**	337
Draws on revolving credit agreement, expiring 2006		**–**	55
Unamortized premium and discount, net		**(8)**	(3)
Current portion of long-term debt		**(48)**	(48)
Long-term debt, net		**2,554**	1,912
Florida Progress Funding Corporation (See Note 24)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(39)**	(39)
Long-term debt, net		**270**	270
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2006-2008	6.84%	**140**	140
Miscellaneous notes		**2**	1
Current portion of long-term debt		**(61)**	(1)
Long-term debt, net		**81**	140
Progress Energy consolidated long-term debt, net		**$10,446**	$9,521

At December 31, 2005, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2005, we had no outstanding borrowings under our credit facilities. For 2004, outstanding borrowings under Progress Energy, Inc.'s 364-day credit facility are included in short-term obligations. Outstanding borrowings under all other credit facilities are included in long-term debt in 2004. At December 31, 2004, we had $260 million outstanding under our credit facilities classified as short-term obligations at a weighted-average interest rate of 3.18%. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2005:

(in millions)	Description	Total	Outstanding	Reserved [a]	Available
Progress Energy, Inc.	Five-year (expiring 8/5/09)	$1,130	$–	$(150)	$980
PEC	Five-year (expiring 6/28/10)	450	–	(73)	377
PEF	Five-year (expiring 3/28/10)	450	–	(102)	348
Total credit facilities		$2,030	$–	$(325)	$1,705

[a] To the extent amounts are reserved for commercial paper outstanding, they are not available for additional borrowings. In addition, at December 31, 2005 and 2004, Progress Energy, Inc. had a total amount of $150 million reserved for backing of letters of credit. At December 31, 2005, the actual amount of letters of credit issued was $33 million.

In addition to the committed RCAs at December 31, 2005, we had an $800 million 364-day credit agreement, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, Progress Energy, Inc. retired $800 million of its 6.75% Senior Notes, thus effectively terminating the 364-day credit agreement.

The following table summarizes our outstanding commercial paper and other short-term debt classified as short-term obligations and related weighted-average interest rates at December 31, 2005 and 2004:

(in millions)	2005		2004	
Progress Energy, Inc.	–	$–	2.75%	$170
PEC	4.65%	73	2.77%	131
PEF	4.75%	102	2.80%	123
Progress Energy, consolidated	4.71%	$175	2.77%	$424

The following table presents the aggregate maturities of long-term debt at December 31, 2005:

(in millions)	
2006	$513
2007	674
2008	1,277
2009	401
2010	406
Thereafter	7,781
Total	$11,052

At December 31, 2005, we classified $397 million, related to the retirement of $800 million in Progress Energy, Inc. 6.75% Senior Notes on March 1, 2006, as long-term debt. Settlement of this obligation is not expected to require the use of working capital in 2006 as we have the intent and ability to refinance this debt on a long-term basis.

On January 13, 2006, Progress Energy, Inc. issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010, receiving net proceeds of $397 million. These senior notes are unsecured. Interest on the Floating Rate Senior Notes will be based on three-month LIBOR plus 45 basis points and will be reset quarterly. We used the net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006. Pending the application of the proceeds described above, we invested the net proceeds in short-term, interest-bearing, investment-grade securities.

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy, Inc.'s, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. These include maximum debt to total capital ratios (leverage), a minimum interest coverage ratio, material adverse change clauses and cross-default provisions.

All of the credit facilities include a defined maximum total debt to total capital ratio. At December 31, 2005, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Progress Energy, Inc.	68%	60.7%
PEC	65%	55.2%
PEF	65%	50.9%

[a] Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees that are not recorded on the Consolidated Balance Sheets.

Progress Energy, Inc.'s five-year credit facility has a financial covenant for interest coverage. The covenant requires Progress Energy, Inc.'s earnings before interest, taxes, and depreciation and amortization to interest expense ratio to be at least 2.5 to 1. For the year ended December 31, 2005, the ratio was 3.9 to 1.

MATERIAL ADVERSE CHANGE CLAUSE

Pursuant to the terms of Progress Energy, Inc.'s five-year credit facility, even in the event of a material adverse change (MAC) in our financial condition, we may continue to borrow funds so long as the proceeds are used to repay maturing commercial paper balances. The other credit facilities of Progress Energy, Inc., PEC, and PEF do not include a provision under which lenders could refuse to advance funds in the event of a MAC.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for Progress Energy, Inc. and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy, Inc.'s cross-default provision applies only to Progress Energy, Inc. and its significant subsidiaries, as defined in the credit agreement (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. and PVI). PEC's and PEF's cross-default provisions apply only to defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not other affiliates of PEC and PEF.

Additionally, certain of Progress Energy, Inc.'s long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of Progress Energy, Inc., primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4.3 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy, Inc.'s Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends. Certain documents restrict the payment of dividends by Progress Energy, Inc.'s subsidiaries as outlined below.

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2005, none of PEC's retained earnings was restricted.

In addition, PEC's Articles of Incorporation provide that cash dividends on common stock shall be limited to 75 percent of net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2005, PEC's common stock equity was approximately 45.6 percent of total capitalization.

PEF's mortgage indenture provides that it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943. At December 31, 2005, none of PEF's retained earnings was restricted.

In addition, PEF's Articles of Incorporation provide that no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceed all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. At December 31, 2005, none of PEF's cash dividends or distributions on common stock was restricted.

PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2005, PEF's common stock equity was approximately 50.1 percent of total capitalization.

C. Collateralized Obligations

PEC's and PEF's first mortgage bonds are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2005, PEC and PEF had a total of approximately $2.869 billion and $1.871 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

See Note 19 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. Hedging Activities

We use interest rate derivatives to adjust the fixed and variable rate components of our debt portfolio and to hedge cash flow risk related to commercial paper and fixed-rate debt to be issued in the future. See discussion of risk management activities and derivative transactions at Note 18.

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. Investments

At December 31, 2005 and 2004, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

(in millions)	2005	2004
Nuclear decommissioning trust (See Note 5D)	**$1,133**	$1,044
Investments in equity securities [(a)]	**7**	3
Equity method investments[(b)]	**27**	26
Cost investments [(c)]	**13**	14
Benefit investment trusts [(d)]	**77**	76
Company-owned life insurance [(d)]	**153**	145
Marketable debt securities [(e)]	**191**	82
Total	**$1,601**	$1,390

(a) Certain investments in equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115 (See Note 1). These investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(b) Investments in unconsolidated companies are included in the Consolidated Balance Sheets in miscellaneous other property and investments using the equity method of accounting (See Note 1). These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 21).

(c) Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

(d) Investments in company-owned life insurance and other benefit plan assets are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the short maturity of the instruments.

(e) PEC actively invests available cash balances in various financial instruments, such as tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through arrangements with banks that provide daily and weekly liquidity and 7-, 28- and 35-day auctions that allow for the redemption of the investment at its face amount plus earned income. As PEC intends to sell these instruments within one year or less, generally within 30 days, from the balance sheet date, they are classified as short-term investments.

B. Fair Value of Financial Instruments

DEBT

The carrying amount of our long-term debt, including current maturities, was $10.959 billion and $9.870 billion at December 31, 2005 and 2004, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $11.491 billion and $10.843 billion at December 31, 2005 and 2004, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants (See Note 5D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents that are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. Our available-for-sale securities at December 31, 2005 and 2004 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2005 *(in millions)*	**Book Value**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Equity securities	**$411**	**$257**	**$5**	$663
Debt securities	**680**	**7**	**7**	680
Cash equivalents	**18**	**–**	**–**	18
Total	**$1,109**	**$264**	**$12**	**$1,361**
2004 *(in millions)*	Book Value	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity securities	$387	$219	$6	$600
Debt securities	538	12	2	548
Cash equivalents	17	–	–	17
Total	$942	$231	$8	$1,165

At December 31, 2005, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$15
Due after one through five years	138
Due after five through 10 years	151
Due after 10 years	376
Total	$680

Selected information about our sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2005**	2004	2003
Proceeds	**$2,053**	$3,200	$3,374
Realized gains	**26**	55	21
Realized losses	**19**	24	25

The following table presents the fair value and gross unrealized losses of our available-for-sale securities at December 31 aggregated by the length of time the securities have been in a continuous loss position.

2005	**12 Months or Less**		**Greater than 12 Months**		**Total**	
(in millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Equity securities	**$653**	**$3**	**$10**	**$2**	**$663**	$5
Debt securities	**653**	**7**	**27**	**–**	**680**	7
Cash equivalents	**18**	**–**	**–**	**–**	**18**	–
Total	**$1,324**	**$10**	**$37**	**$2**	**$1,361**	$12
2004	12 Months or Less		Greater than 12 Months		Total	
(in millions)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Equity securities	$587	$3	$13	$3	$600	$6
Debt securities	546	2	2	–	548	2
Cash equivalents	17	–	–	–	17	–
Total	$1,150	$5	$15	$3	$1,165	$8

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders.

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	2005	2004
Deferred income tax assets		
Asset retirement obligation liability	**$135**	$169
Compensation accruals	**101**	99
Deferred revenue	**54**	8
Derivative instruments	**–**	25
Environmental remediation liability	**27**	21
Income taxes refundable through future rates	**179**	115
Postretirement and pension benefits	**275**	188
Unbilled revenue	**30**	35
Other	**112**	128
Federal income tax credit carry forward	**957**	778
State net operating loss carry forward (net of federal expense)	**45**	26
Valuation allowance	**(39)**	(25)
Total deferred income tax assets	**1,876**	1,567
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,420)**	(1,513)
Deferred fuel recovery	**(89)**	(68)
Deferred storm costs	**(94)**	(141)
Derivative instruments	**(74)**	–
Income taxes recoverable through future rates	**(187)**	(181)
Investments	**(31)**	–
Prepaid pension costs	**–**	(16)
Other	**(65)**	(65)
Total deferred income tax liabilities	**(1,960)**	(1,984)
Total net deferred income tax liabilities	**$(84)**	$(417)

The above amounts were classified in the Consolidated Balance Sheets as follows:

(in millions)	2005	2004
Current deferred income tax assets	**$50**	$112
Noncurrent deferred income tax assets, included in other assets and deferred debits	**30**	14
Current deferred income tax liabilities, included in other current liabilities	**(1)**	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(163)**	(543)
Total net deferred income tax liabilities	**$(84)**	$(417)

Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2005 and 2004 include $115 million and $105 million, respectively, related to probable tax liabilities on which we accrue interest that would be payable with the related tax amount in future years.

At December 31, 2005, the federal income tax credit carry forward includes $925 million of alternative minimum tax credits that do not expire and $32 million of general business credits that will expire during the period 2022 through 2025. The alternative minimum tax credit carry forward at December 31, 2005, includes $3 million that would be limited if a change in ownership were to occur with respect to certain indirect wholly owned subsidiary companies.

At December 31, 2005, we had gross state net operating loss carry forwards of $901 million that will expire during the period 2009 through 2024.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $14 million during 2005. We believe it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

We establish accruals for certain tax contingencies when, despite our belief that our tax return positions are fully supported, we believe that certain positions may be challenged and that it is probable our positions may not be fully sustained. We are under continuous examination by the IRS and other tax authorities and we account for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2005 and 2004, we had recorded $60 million of tax contingency reserves, excluding accrued interest and penalties, which were included in other current liabilities on the Consolidated Balance Sheets.

Considering all tax contingency reserves, we do not expect the resolution of these matters to have a material impact on our financial position or result of operations. The tax contingency reserves relate primarily to capitalization and basis issues.

Reconciliations of our effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2005	2004	2003
Effective income tax rate	**(6.8)%**	12.9%	(16.2)%
State income taxes, net of federal benefit	**(3.4)**	(6.9)	(3.8)
Minority interest	**(1.9)**	(1.0)	0.1
Federal tax credits	**43.6**	26.7	50.6
Investment tax credit amortization	**2.0**	1.7	2.3
Employee stock ownership plan dividends	**1.9**	1.8	2.1
Domestic manufacturing deduction	**1.3**	–	–
Other differences, net	**(1.7)**	(0.2)	(0.1)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Our effective income tax rate is favorably impacted by federal tax credits resulting from synthetic fuel production.

Income tax expense (benefit) applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)		2005	2004	2003
Current	– federal	**$351**	$238	$297
	– state	**75**	72	57
Deferred	– federal	**(137)**	14	(86)
	– state	**(32)**	16	(19)
State net operating loss carry forward		**(6)**	(5)	–
Synthetic fuel tax credit		**(283)**	(215)	(346)
Investment tax credit		**(13)**	(14)	(16)
Total income tax expense (benefit)		**$(45)**	$106	$(113)

Total income tax expense (benefit) applicable to continuing operations excluded the following:

- Less than $1 million of deferred tax expense and $16 million of deferred tax benefit related to the cumulative effect of changes in accounting principle recorded net of tax during 2005 and 2003, respectively. There was no cumulative effect of changes in accounting principle recorded during 2004.
- Taxes related to discontinued operations recorded net of tax for 2005, 2004 and 2003, which are presented separately in Notes 3A, 3B and 3H.
- Taxes related to other comprehensive income recorded net of tax for 2005, 2004 and 2003, which are presented separately in the Consolidated Statements of Comprehensive Income.
- Current tax benefit of $2 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004. There was no amount recorded in common stock for excess tax deductions during 2003.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Code. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29/45K if certain requirements are satisfied (See Note 23D).

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuel facilities purchased by subsidiaries of Florida Progress in October 1999. The payments, if any, would be based on the net after-tax cash flows the facilities generate. The CVO liability is adjusted to reflect market price fluctuations. The unrealized loss/gain recognized due to these market fluctuations is recorded in other, net on the Consolidated Statements of Income (See Note 21). The liability, included in other liabilities and deferred credits, at December 31, 2005 and 2004, was $7 million and $13 million, respectively.

16. BENEFIT PLANS

A. Postretirement Benefits

We have a noncontributory defined benefit retirement plan for substantially all full-time employees that provides pension benefits. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, we provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. We use a measurement date of December 31 for our pension and OPEB plans.

EFIT PLANS

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

To determine the market-related value of assets, we use a five-year averaging method for a portion of its pension assets and fair value for the remaining portion. We have historically used the five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

The components of the net periodic benefit cost for the years ended December 31 were:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2005	2004	2003	2005	2004	2003
Service cost	$47	$54	$52	$9	$12	$15
Interest cost	117	110	108	33	31	33
Expected return on plan assets	(147)	(155)	(144)	(5)	(5)	(4)
Amortization of actuarial loss	35	21	25	8	4	5
Other amortization, net	1	–	–	1	1	4
Net periodic cost	53	30	41	46	43	53
Additional cost (benefit) recognition [a]	(15)	(16)	(18)	2	2	2
Net periodic cost recognized	$38	$14	$23	$48	$45	$55

[a] Relates to the acquisition of Florida Progress (See Note 16B).

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to the voluntary enhanced retirement program (See Note 17) of $123 million for pension benefits and $19 million for other postretirement benefits. In 2003, we also recorded curtailment and settlement effects related to the disposition of NCNG, which are reflected in income/(loss) from discontinued operations in the Consolidated Statements of Income. These effects included a pension-related loss of $13 million and an OPEB-related gain of $1 million.

We used the following weighted-average actuarial assumptions in the calculation of our net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
Discount rate	5.70%	6.30%	6.60%	5.70%	6.30%	6.60%
Rate of increase in future compensation						
Bargaining	3.50%	3.50%	3.50%	–	–	–
Nonbargaining	–	–	4.00%	–	–	–
Supplementary plans	5.25%	5.00%	4.00%	–	–	–
Expected long-term rate of return on plan assets	9.00%	9.25%	9.25%	8.25%	8.50%	8.45%

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plans assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. We have chosen to use an expected long-term rate of 9.0%, the low end of the range, beginning in 2005.

PREPAID/ACCRUED BENEFIT COSTS

Reconciliations of the changes in the benefit obligations and the funded status follow:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2005	2004	2005	2004
Projected benefit obligation at January 1	$1,961	$1,772	$538	$472
Service cost	47	54	9	12
Interest cost	117	110	33	31
Benefit payments	(182)	(98)	(33)	(23)
Plan amendment	–	21	–	–
Special termination benefits	123	–	19	–
Actuarial loss (gain)	98	102	84	46
Obligation at December 31	2,164	1,961	650	538
Fair value of plan assets at December 31	1,770	1,774	76	70
Funded status	(394)	(187)	(574)	(468)
Unrecognized transition obligation	–	–	9	10
Unrecognized prior service cost	23	24	5	6
Unrecognized net actuarial loss	570	530	170	94
Minimum pension liability adjustment	(546)	(470)	–	–
Accrued cost at December 31, net (See Note 16B)	$(347)	$(103)	$(390)	$(358)

The net accrued pension cost of $347 million at December 31, 2005, is included in accrued pension and other benefits in the Consolidated Balance Sheets. The net accrued pension cost of $103 million at December 31, 2004, is recognized in the Consolidated Balance Sheets as prepaid pension cost of $42 million and accrued benefit cost of $145 million, which is included in accrued pension and other benefits. The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $2.16 and $1.72 billion at December 31, 2005 and 2004, respectively. Those plans had accumulated benefit obligations totaling $2.12 and $1.71 billion at December 31, 2005 and 2004, respectively, and plan assets of $1.77 and $1.57 billion at December 31, 2005 and 2004, respectively. The total accumulated benefit obligation for pension plans was $2.12 and $1.90 billion at December 31, 2005 and 2004, respectively. The accrued OPEB cost is included in accrued pension and other benefits in the Consolidated Balance Sheets.

A minimum pension liability adjustment of $546 million was recorded at December 31, 2005. This adjustment resulted in a charge of $23 million to intangible assets, a $180 million charge to a pension-related regulatory liability (See Note 16B), an $83 million charge to a regulatory asset pursuant to an FPSC order and a pre-tax charge of $260 million to accumulated other comprehensive loss, a component of common stock equity. A minimum pension liability adjustment of $470 million was recorded at December 31, 2004. This adjustment resulted in a charge of $24 million to intangible assets, a $150 million charge to a pension-related regulatory liability (See Note 16B), a $67 million charge to a regulatory asset pursuant to an FPSC order and a pre-tax charge of $229 million to accumulated other comprehensive loss, a component of common stock equity.

The following weighted-average actuarial assumptions were used in the calculation of our year-end obligations:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.65%	5.90%	5.65%	5.90%
Rate of increase in future compensation				
Bargaining	3.50%	3.50%	–	
Supplementary plans	5.25%	5.25%	–	
Initial medical cost trend rate for pre-Medicare Act benefits	–	–	8.25%	7.25%
Initial medical cost trend rate for post-Medicare Act benefits	–	–	8.25%	7.25%
Ultimate medical cost trend rate	–	–	5.00%	5.00%
Year ultimate medical cost trend rate is achieved	–	–	2013	2008

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash

Balance' Pension Plan." Therefore, effective December 31, 2003, we began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

(in millions)	
1 percent increase in medical cost trend rate	
Effect on total of service and interest cost	$5
Effect on postretirement benefit obligation	65
1 percent decrease in medical cost trend rate	
Effect on total of service and interest cost	(4)
Effect on postretirement benefit obligation	(54)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, substantially all employer contributions represent benefit payments made directly from our assets except for the 2004 pension amount. The remaining benefit payments were made directly from plan assets. In 2004, we made a required contribution of approximately $24 million directly to pension plan assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the net cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments.

Reconciliations of the fair value of plan assets at December 31 follow:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2005**	2004	**2005**	2004
Fair value of plan assets at January 1	**$1,774**	$1,631	**$70**	$65
Actual return on plan assets	**170**	211	**5**	8
Benefit payments	**(182)**	(98)	**(33)**	(23)
Employer contributions	**8**	30	**34**	20
Fair value of plan assets at December 31	**$1,770**	$1,774	**$76**	$70

The asset allocation for the benefit plans at the end of 2005 and 2004 and the target allocation for the plans, by asset category, are presented in the following table:

	Pension Benefits			Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End		Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2006	**2005**	2004	2006	**2005**	2004
Equity - domestic	40%	**44%**	47%	28%	**32%**	34%
Equity - international	15%	**22%**	21%	11%	**16%**	15%
Debt - domestic	20%	**13%**	9%	43%	**37%**	35%
Debt - international	10%	**8%**	11%	7%	**6%**	8%
Other	15%	**13%**	12%	11%	**9%**	8%
Total	100%	**100%**	100%	100%	**100%**	100%

For pension plan assets and a substantial portion of OPEB plan assets, we set target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, external investment managers who have complementary investment philosophies and approaches are employed to manage the assets. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2006, we expect to make $10 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $164, $124, $127, $133, $137 and $789, respectively. The expected benefit payments for the OPEB plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $41, $43, $45, $46, $48 and $245, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from our assets. The benefit payment amounts reflect our net cost after any participant contributions. We expect to begin receiving prescription drug-related federal subsidies in 2006, and the expected subsidies for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $3, $3, $3, $4, $4 and $30, respectively.

B. Florida Progress Acquisition

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. Accordingly, a portion of the accrued OPEB cost reflected in the table above has a corresponding regulatory asset at December 31, 2005, and 2004 (See Note 7A). As indicated in the minimum pension adjustment information, a pension-related regulatory liability was charged, and fully eliminated, at December 31, 2005. At December 31, 2004, a portion of the prepaid pension cost has a corresponding regulatory liability (See Note 7A). Pursuant to its rate treatment, PEF recognized additional periodic pension credits and additional periodic OPEB costs, as indicated in the net periodic cost information above.

17. SEVERANCE

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. The cost-management initiative is designed to permanently reduce by $75 million to $100 million our projected growth in annual O&M expenses by the end of 2007. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, as described below. The workforce restructuring concluded on December 1, 2005.

We recorded $31 million of severance expense during the first quarter of 2005 for the workforce restructuring and implementation of an automated meter reading initiative at PEF based on the approximate number of positions to be eliminated. During the second quarter of 2005, 1,447 employees eligible for participation in the voluntary enhanced retirement program elected to participate. Consequently, in the second and fourth quarters of 2005, we decreased our estimated severance costs by $13 million each quarter due to the impact of the employees electing participation in the voluntary enhanced retirement program. The severance expenses are primarily included in O&M expense on the Consolidated Statements of Income.

The accrued severance expense will be paid over time. The activity in the severance liability was as follows:

(in millions)	
Balance as of January 1, 2005	$5
Severance costs accrued	31
Adjustments	(26)
Payments	(4)
Balance at December 31, 2005	**$6**

During 2005, we recorded a $141 million charge in the second quarter and a $1 million charge in the third quarter related to postretirement benefits that will be paid over time to eligible employees who elected to participate in the voluntary enhanced retirement program (See Note 16). In addition, we recorded a $17 million charge for early retirement incentives to be paid over time to certain employees.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

We are exposed to various risks related to changes in market conditions. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. We minimize such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations. Additionally, in the normal course of business, some of our affiliates may enter into hedge transactions with one another.

A. Commodity Derivatives

[illegible]

Most of our commodity contracts are not derivatives pursuant to SFAS No. 133, "Accounting for Derivative and Hedging Activities" (SFAS No. 133), or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

In 2003, we recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the provisions of FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (DIG Issue C20). The related liability is being amortized to earnings over the term of the related contract (See Note 21). At December 31, 2005 and 2004, the remaining liability was $19 million and $26 million, respectively.

[illegible] DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to our results of operations during 2005, 2004 and 2003. We did not have material outstanding positions in such contracts at December 31, 2005 and 2004, other than those receiving regulatory accounting treatment at PEF, as discussed below.

PEF has derivative instruments related to its exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits and a $6 million long-term derivative liability position included in other liabilities and deferred credits. At December 31, 2004, the fair values of the instruments were a $2 million long-term derivative asset position included in other assets and deferred debits and a $5 million short-term derivative liability position included in other current liabilities.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of natural gas and power for our forecasted purchases and sales. Realized gains and losses are recorded net in operating revenues or operating expenses, as appropriate. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2005, 2004 and 2003.

The fair values of commodity cash flow hedges at December 31 were as follows:

(in millions)	2005	2004
Fair value of assets	**$170**	$–
Fair value of liabilities	**(58)**	(15)
Fair value, net	**$112**	$(15)

The following table presents selected information related to commodity cash flow hedges at December 31, 2005:

(term in years/ millions of dollars)	Maximum Term[a]	Accumulated Other Comprehensive Income/(Loss), net of Tax	Portion Expected to be Reclassified to Earnings during the Next 12 Months[b]
Commodity cash flow hedges	9	$69	$(17)

[a] The majority of hedges in fair value liability positions are currently classified as short-term and the majority of hedges in fair value asset positions are currently classified as long-term.

[b] Due to the volatility of the commodities markets, the value in accumulated other comprehensive income/(loss) (OCI) is subject to change prior to its reclassification into earnings.

At December 31, 2004, we had $9 million of after-tax deferred losses in OCI related to commodity cash flow hedges.

B. Interest Rate Derivatives – Fair Value or Cash Flow Hedges

We use cash flow hedging strategies to reduce exposure to changes in cash flow due to fluctuating interest rates. We use fair value hedging strategies to reduce exposure to changes in fair value due to interest rate changes. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates.

The fair values of open interest rate hedges at December 31 were as follows:

(in millions)	2005	2004
Interest rate cash flow hedges	$1	$(2)
Interest rate fair value hedges	$(2)	$3

CASH FLOW HEDGES

Gains and losses from cash flow hedges are recorded in OCI and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges was not material to our results of operations for 2005, 2004 and 2003.

The following table presents selected information related to interest rate cash flow hedges included in OCI at December 31, 2005:

(term in years/ millions of dollars)	Maximum Term	Accumulated Other Comprehensive Income/ (Loss), net of Tax[a]	Portion Expected to be Reclassified to Earnings during the Next 12 Months[b]
Interest rate cash flow hedges	1	$(13)	$(2)

[a] Includes amounts related to terminated hedges.
[b] Actual amounts that will be reclassified to earnings may vary from the expected amounts presented above as a result of changes in interest rates.

At December 31, 2005 and 2004, we had $100 million notional and $331 million notional, respectively, of interest rate cash flow hedges.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2005 and 2004, we had $150 million notional of interest rate fair value hedges.

At December 31, 2005 and 2004, we had a $2 million loss and a $9 million gain, respectively, of basis adjustments in long-term debt related to terminated interest rate fair value hedges, which are being amortized over periods ending in 2006 through 2008 coinciding with the maturities of the related debt instruments.

19. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2005, the Parent had issued $1.56 billion of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 24). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the PUHCA. The repeal of PUHCA effective February 8, 2006, and subsequent regulation by the FERC is not anticipated to change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered. Amounts receivable from and/or payable to affiliated companies for these services are included in receivables from affiliated companies and payables to affiliated companies on the Balance Sheets.

At December 31, 2005, the Parent's guarantees include $169 million to support nuclear decommissioning. PEC determined that its external funding levels did not fully meet the nuclear decommissioning financial assurance levels required by the NRC; therefore, PEC obtained the Parent's guarantee.

Progress Fuels sells coal to PEF for an insignificant profit. These intercompany revenues and expenses are eliminated in consolidation; however, in accordance with SFAS No. 71 profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, of $402 million, $331 million and $347 million for the years ended December 31, 2005, 2004 and 2003, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. Beginning in 2006, PEF will enter into coal contracts on its own behalf.

We sold NCNG to Piedmont Natural Gas Company, Inc. on September 30, 2003 (See Note 3H). Prior to disposition, NCNG sold natural gas to affiliates. During the year ended December 31, 2003, gas sales from NCNG to PEC amounted to $11 million. The gas sales for 2003 indicated above exclude any sales subsequent to September 2003. These revenues are included in discontinued operations on the Consolidated Statements of Income.

20. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable segments are: PEC, PEF, Progress Ventures and Coal and Synthetic Fuels. During 2005, we realigned our segments due to changes in the operations of certain businesses and the reclassification of our coal mining business to discontinued operations. These changes are consistent with the manner in which management currently reviews our operations. Prior year periods have been restated for our segment realignments.

Our PEC and PEF business segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. Prior to December 2005, we disclosed a PEC Electric segment that was comprised of utility operations and excluded immaterial operations of PEC's nonregulated subsidiaries, which were included in Corporate and Other. Management has realigned the PEC segment to review the PEC operations on a consolidated basis as the results of operations and financial position are not materially different between PEC Electric and PEC.

Our Progress Ventures segment is comprised of Competitive Commercial Operations (CCO) and natural gas operations (Gas) and is involved in nonregulated electric generation and energy marketing activities and natural gas drilling and production in Texas and Louisiana. Prior to December 2005, CCO had been reported as a separate segment and Gas was included within our previously reported Fuels segment. Progress Ventures' legal structure is not currently aligned with the functional management and financial reporting of the Progress Ventures segment.

Our Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuel as defined under the Code, coal terminal services, and fuel transportation and delivery. Operations involving coal terminals and synthetic fuels activities were included within our previously reported Fuels segment prior to 2005. The remaining portions of our previously reported Fuels segment are included within Coal and Synthetic

Fuels due to their operational relationship with the segment's activities and their relative immateriality.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC as well as other nonregulated business areas. These nonregulated business areas include telecommunications and other nonregulated subsidiaries that do not separately meet the disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131). Included in the 2004 losses is a $43 million pre-tax ($29 million after-tax) settlement agreement that Strategic Resource Solutions Corp. (SRS) reached with the San Francisco United School District related to civil proceedings. The profit or loss of the identified segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

Prior to its divestiture in 2005, Rail Services was reported as a separate segment (See Note 3B). The operations of Rail Services were reclassified to discontinued operations in the first quarter of 2005. During the fourth quarter of 2005, we reclassified our coal mining operations as discontinued operations (See Note 3A). Prior to 2005, our coal mining operations were included within our previously reported Fuels segment. Our Rail Services and coal mining operations are not included in the results from continuing operations during the periods reported. Assets and capital and investment expenditures of discontinued operations are not included in the tables presented below.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the Coal and Synthetic Fuel segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the Coal and Synthetic Fuel segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits realized for 2005, 2004 and 2003 were not significant. Income tax expense (benefit) by segment includes the Parent's allocation to profitable subsidiaries of income tax benefits not related to acquisition interest expense in accordance with the Tax Agreement. Due to the repeal of PUHCA, the Parent will stop allocating these tax benefits in 2006.

In the following tables, capital and investment expenditures include property additions, acquisitions of nuclear fuel and other capital investments.

(in millions)	PEC	PEF	Progress Ventures	Coal and Synthetic Fuels	Corporate and Other	Eliminations	Totals
Year ended December 31, 2005							
Revenues							
Unaffiliated	**$3,991**	**$3,955**	**$853**	**$1,242**	**$67**	**$–**	**$10,108**
Intersegment	**–**	**–**	**–**	**402**	**447**	**(849)**	**–**
Total revenues	**3,991**	**3,955**	**853**	**1,644**	**514**	**(849)**	**10,108**
Depreciation and amortization	**561**	**334**	**94**	**38**	**47**	**–**	**1,074**
Total interest charges, net	**192**	**126**	**5**	**34**	**372**	**(89)**	**640**
Postretirement and severance charges	**55**	**102**	**1**	**5**	**1**	**–**	**164**
Impairment of long-lived assets and investments	**(1)**	**–**	**–**	**–**	**–**	**–**	**(1)**
Income tax expense (benefit)	**239**	**121**	**7**	**(350)**	**(62)**	**–**	**(45)**
Segment profit (loss)	**490**	**258**	**21**	**169**	**(211)**	**–**	**727**
Total assets	**11,502**	**8,318**	**2,371**	**472**	**18,024**	**(13,773)**	**26,914**
Capital and investment expenditures	**682**	**543**	**183**	**16**	**29**	**(19)**	**1,434**
Year ended December 31, 2004							
Revenues							
Unaffiliated	$3,629	$3,525	$401	$899	$71	$–	$8,525
Intersegment	–	–	–	331	440	(771)	–
Total revenues	3,629	3,525	401	1,230	511	(771)	8,525
Depreciation and amortization	570	281	101	38	45	–	1,035
Total interest charges, net	192	114	11	37	360	(86)	628
Postretirement and severance charges	2	–	–	1	–	–	3
Income tax expense (benefit)	239	174	55	(280)	(82)	–	106
Segment profit (loss)	458	333	81	88	(231)	–	729
Total assets	10,787	7,924	2,086	542	17,590	(13,570)	25,359
Capital and investment expenditures	620	492	154	10	26	(12)	1,290
Year ended December 31, 2003							
Revenues							
Unaffiliated	$3,600	$3,152	$285	$716	$46	$–	$7,799
Intersegment	–	–	–	347	440	(787)	–
Total revenues	3,600	3,152	285	1,063	486	(787)	7,799
Depreciation and amortization	562	307	78	35	27	–	1,009
Total interest charges, net	197	91	6	29	378	(94)	607
Impairment of long-lived assets and investments	(21)	–	–	–	–	–	(21)
Income tax expense (benefit)	241	147	25	(434)	(47)	(45)	(113)
Segment profit (loss)	502	295	54	190	(230)	–	811
Total assets	10,938	7,280	2,195	599	17,802	(13,368)	25,446
Capital and investment expenditures	511	577	606	24	19	–	1,737

21. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income, impairment of investments, and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. AFUDC equity represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets. The components of other, net as shown on the accompanying Consolidated Statements of Income for the years ended December 31 were as follows:

(in millions)	2005	2004	2003
Other income			
Nonregulated energy and delivery services income	$32	$28	$26
DIG Issue C20 amortization (Note 18A)	7	9	2
Contingent value obligation unrealized gain (Note 15)	6	9	–
Investment gains	7	4	12
Income from equity investments	1	3	–
AFUDC equity	16	12	14
Other	15	13	15
Total other income	84	78	69
Other expense			
Nonregulated energy and delivery services expenses	24	21	20
Donations	18	15	15
Investment losses	–	1	6
Contingent value obligation unrealized loss (Note 15)	–	–	9
Loss from equity investments	7	8	31
Loss on debt extinguishment and interest rate collars	–	15	–
FERC audit settlement	7	–	–
Indemnification liability (Note 22B)	16	–	–
Other	17	30	15
Total other expense	89	90	96
Other, net	$(5)	$(12)	$(27)

22. ENVIRONMENTAL MATTERS

We are subject to federal, state and local regulations addressing hazardous and solid waste management, air and water quality and other environmental matters.

A. Hazardous and Solid Waste Management

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina or the state of Florida, as described below in greater detail. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each potentially responsible parties (PRPs) at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. A discussion of sites by legal entity follows below.

We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. We measure our liability for these sites based on available evidence including our experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. For all sites, as assessments are developed and analyzed, we will accrue costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates will change and additional losses, which could be material, may be incurred in the future.

PEC and PEF filed claims with general liability insurance carriers to recover costs arising from actual or potential environmental liabilities for remediation of certain sites. No material claims are currently pending. We may file further claims with respect to sites for which claims were not previously presented.

In addition to the Utilities' sites, discussed under "PEC" and "PEF" below, our environmental sites include the following related to our nonregulated operations.

In 2001, we, through our Progress Fuels subsidiary, established an accrual to address indemnities and retained an environmental liability associated with the sale of our Inland Marine Transportation business. In 2003, the accrual was reduced to $4 million based on a change in estimate. At December 31, 2005 and 2004, the remaining accrual balance was approximately $3 million. Expenditures related to this liability were not material to our financial condition during 2005 and 2004.

We are voluntarily addressing certain historical sites. An immaterial accrual has been established to address investigation expenses related to these sites. At this time, the total costs that may be incurred in connection with these sites cannot be determined.

On March 24, 2005, we completed the sale of our Progress Rail subsidiary. In connection with the sale, we incurred indemnity obligations related to certain pre-closing liabilities, including certain environmental matters (See discussion under Guarantees in Note 23C).

PEC

There are nine former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation.

In September 2005, the EPA advised PEC that it had been identified as a PRP at the Carolina Transformer site located in Fayetteville, N.C. The EPA offered PEC and a number of other PRPs the opportunity to share the reimbursement of approximately $36 million to the EPA for past expenditures in addressing conditions at the site. Although a loss is considered probable, an agreement among PRPs has not been reached; consequently, it is not possible at this time to reasonably estimate the total amount of PEC's obligation for remediation of the Carolina Transformer site. PEC may file claims with respect to this site. The outcome of this matter cannot be predicted.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. The EPA offered PEC and a number of other PRPs the opportunity to negotiate cleanup of the site and reimbursement to the EPA for EPA's past expenditures in addressing conditions at the site. In September 2005, PEC and several other PRPs signed a settlement agreement, which requires the participating PRPs to provide approximately $5 million to cover the cleanup cost and repay less than $1 million of EPA's past costs. PEC has accrued its portion of these estimated costs. Based upon additional assessment work performed at the site during the first quarter of 2006, it is probable that additional costs beyond the EPA's original cost estimate will be incurred. However, the range of additional losses cannot be determined at this time. PEC may file claims with respect to this site. The outcome of this matter cannot be predicted.

At December 31, 2005 and 2004, PEC's accruals for probable and estimable costs related to various environmental sites, which are included in other liabilities and deferred credits and are expected to be paid out over one to five years, were $7 million and $9 million, respectively. The amount includes insurance fund proceeds that PEC received to address costs associated with environmental liabilities related to its involvement with some sites. All eligible expenses related to these sites are charged against a specific fund containing these proceeds. During 2005, PEC spent approximately $6 million, accrued approximately $4 million and received no insurance proceeds related to environmental remediation. During 2004, PEC spent approximately $2 million related to environmental remediation.

On March 30, 2005, the North Carolina Division of Water Quality renewed a PEC permit for the continued use of coal combustion products generated at any of its coal-fired plants located in the state. Following review of the permit conditions, which could significantly restrict the reuse of coal ash and result in higher ash management costs, the permit was adjudicated. The outcome of this matter cannot be predicted.

PEF

At December 31, 2005 and 2004, PEF's accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits and are expected to be paid out over one to 15 years, were:

(in millions)	2005	2004
Remediation of distribution and substation transformers	$20	$27
MGP and other sites	18	18
Total accrual for environmental sites	$38	$45

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the Florida Department of Environmental Protection (FDEP), PEF is in the process of examining distribution transformer sites and substation sites for potential equipment integrity issues that could result in the need for mineral oil-impacted soil remediation. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for review of distribution transformer sites, PEF currently expects to have completed its review by the end of 2007. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the years ended December 31, 2005 and 2004, PEF accrued approximately $2 million and $19 million, respectively, and spent approximately $9 million and $4 million, respectively, related to the remediation of transformers. PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC.

The amounts for MGP and other sites, in the table above, relate to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation. For the year ended December 31, 2005, PEF made no material accruals, spent approximately $1 million, and received approximately $1 million of additional insurance proceeds. For the year ended December 31, 2004, PEF received approximately $12 million in insurance claim settlement proceeds and recorded a related accrual for associated environmental expenses, as these insurance proceeds are restricted for use in addressing costs associated with environmental liabilities.

In Florida, a risk-based corrective action (RBCA, known as Global RBCA) rule was developed by the FDEP and adopted at the February 2, 2005, Environmental Review Commission hearing. Risk-based corrective action generally means that the corrective action prescribed for contaminated sites can correlate to the level of human health risk imposed by the contamination at the property. The Global RBCA rule expands the use of the risk-based corrective action to all contaminated sites in the state that are not currently in one of the state's waste cleanup programs and has the potential for making future cleanups in Florida more costly to complete. The effective date of the Global RBCA rule was April 17, 2005.

B. Air Quality

We are subject to various current and proposed federal, state and local environmental compliance laws and regulations, which may result in increased planned capital expenditures and O&M expenses. Significant updates to these laws and regulations and related impacts to us since December 31, 2004, are discussed below. Additionally, Congress is considering legislation that would require additional reductions in air emissions of NOx, SO_2, carbon dioxide (CO_2) and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment that will be installed on North Carolina coal-fired generating facilities as part of the Clean Smokestacks Act, enacted in 2002 and discussed below, may address some of the issues outlined above as they relate to PEC. However, the outcome of the matter cannot be predicted.

NEW SOURCE REVIEW (NSR)

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to NSR requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The EPA initiated civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements calling for expenditures by these unaffiliated utilities in excess of $1.0 billion. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related costs through rate adjustments or similar mechanisms.

On June 24, 2005, the Court of Appeals for the District of Columbia Circuit rendered a decision in a suit regarding EPA's NSR rules. As part of the decision, the court struck down a provision excluding pollution control projects from NSR requirements. As a result of this decision, additional regulatory review of our pollution control equipment proposals will be required, adding time and cost to the overall project.

NOx SIP CALL RULE UNDER SECTION 110 OF THE CLEAN AIR ACT (NOx SIP CALL)

The NOx SIP Call is an EPA rule that requires 22 states, including North Carolina, South Carolina and Georgia, to further reduce nitrogen oxide emissions. The NOx SIP Call is not applicable to Florida. Total capital costs to meet the requirements of the final rule under the NOx SIP Call in North Carolina and South Carolina could reach approximately $355 million at PEC, of which approximately $336 million has been incurred through December 31, 2005. This amount also includes the cost to install NOx controls under North Carolina's and South Carolina's programs to comply with the federal eight-hour ozone standard. However, further technical analysis and rulemaking may result in requirements for additional controls at some units. Increased O&M expenses relating to the NOx SIP Call are not expected to be material to our results of operations.

Parties unrelated to us have undertaken efforts to have Georgia excluded from the rule and its requirements. Georgia has not yet submitted a state implementation plan to comply with the Section 110 NOx SIP Call. The outcome of this matter and the impact to our nonregulated operations in Georgia cannot be predicted.

CLEAN SMOKESTACKS ACT

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. In April 2005, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets for NOx and SO_2 from coal-fired plants under the Clean Smokestacks Act of approximately $895 million. We now project that our total capital expenditures to meet these emission targets will be in a range of approximately $1.1 billion to $1.4 billion by the end of 2013, of which approximately $286 million has been spent through December 31, 2005. This increase is primarily due to the higher cost and revised quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for the current projects, and increases in the estimated inflation factor applied to future project costs. We are evaluating various design technology and new generation options that could materially reduce expenditures required by the Clean Smokestacks Act.

Two of the coal-fired generation plants impacted by the Clean Smokestacks Act are jointly owned. The joint owners pay their ownership share of construction costs. In 2005, PEC entered into a contract with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recognized a $16 million liability in the fourth quarter of 2005, based upon the current estimate for Clean Smokestacks Act compliance. As capital cost projections change, it is reasonably possible that additional losses, which could be material, may be incurred in the future.

The Clean Smokestacks Act also freezes the utilities' base rates for five years, which ends in 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the utilities' last general rate case. The Clean Smokestacks Act requires PEC to amortize $569 million, representing 70 percent of the original cost estimate of $813 million, during the five-year rate freeze period. PEC recognized amortization of $147 million, $174 million and $74 million for the years ended December 31, 2005, 2004 and 2003, respectively, and has recognized $395 million in cumulative amortization through December 31, 2005. The remaining amortization requirement of $174 million will be recorded over the two-year period ending December 31, 2007. The Clean Smokestacks Act permits PEC the flexibility to vary the amortization schedule for recording of the compliance costs from none up to $174 million per year. The NCUC will hold a hearing prior to December 31, 2007, to determine cost recovery amounts for 2008 and future periods.

Pursuant to the Clean Smokestacks Act, PEC entered into an agreement with the state of North Carolina to transfer to the state certain NOx and SO_2 emissions allowances that result from compliance with the collective NOx and SO_2 emissions limitations set out in the Clean Smokestacks Act. The Clean Smokestacks Act also required the state to undertake a study of mercury and CO_2 emissions in North Carolina. O&M expenses will significantly increase due to the additional personnel, materials and general maintenance associated with the equipment. O&M expenses are recoverable through base rates, rather than as part of this program. The future regulatory interpretation, implementation or impact of the Clean Smokestacks Act cannot be predicted.

CLEAN AIR INTERSTATE RULE (CAIR) AND MERCURY RULE

On March 10, 2005, the EPA issued the final CAIR. The EPA's rule requires 28 states, including North Carolina, South Carolina, Georgia and Florida, and the District of Columbia to reduce NOx and SO_2 emissions in order to reduce levels of fine particulate matter and impacts to visibility. The CAIR sets emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2.

PEF has joined a coalition of Florida utilities that has filed a challenge to the CAIR as it applies to Florida. A petition for reconsideration and stay, and a petition for judicial review of the CAIR were filed on July 11, 2005. On October 27, 2005, the DC Circuit Court issued an order granting the motion for stay of the proceedings. On December 2, 2005, the EPA announced a reconsideration of four aspects of the CAIR, including its applicability to Florida. While we consider it unlikely that this challenge would eliminate the compliance requirements of the CAIR, it could potentially reduce or delay our costs to comply with the CAIR. The outcome of this matter cannot be predicted.

On March 15, 2005, the EPA finalized two separate but related rules: the Clean Air Mercury Rule (CAMR) that sets emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encourages a cap and trade approach to achieving those caps, and a de-listing rule that eliminated any requirement to pursue a maximum achievable control technology (MACT) approach for limiting mercury emissions from coal-fired power plants. NOx and SO_2 controls also are effective in reducing mercury emissions. However, according to the EPA the second phase cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling NOx and SO_2 under CAIR.

The de-listing rule has been challenged by a number of parties; the resolution of the challenges could impact our final compliance plans and costs. On October 21, 2005, the EPA announced a reconsideration of the CAMR. The outcome of this matter cannot be predicted.

In conjunction with the proposed mercury rule, the EPA proposed a MACT standard to regulate nickel emissions from residual oil-fired units. The EPA withdrew the proposed nickel rule in March 2005.

We are in the process of determining compliance plans and the cost to comply with the CAIR and CAMR. Installation of additional air quality controls is likely to be needed to meet the CAIR and the CAMR requirements. Compliance costs at PEF are eligible for consideration for recovery through the ECRC. The outcome of future petitions for recovery through the ECRC cannot be predicted.

The air quality controls needed to meet compliance with the NOx SIP Call and Clean Smokestacks Act will reduce the costs to meet the CAIR requirements for our North Carolina units at PEC. We currently estimate the total additional compliance costs related to CAIR for PEC could be in a range of approximately $100 million to $200 million. We will continue to review these estimates as compliance plans are further developed. The timing and extent of the costs for future projects will depend upon the final compliance strategy.

We expect PEF to incur significant additional capital and O&M expenses to achieve compliance with the CAIR and CAMR through 2018. We currently estimate the total compliance costs for PEF could be as much as approximately $1.4 billion, of which approximately $2 million has been incurred through December 31, 2005. We will continue to review these estimates as compliance plans are further developed. The timing and extent of the costs for future projects will depend upon the final compliance strategy. We are evaluating various design technology and new generation options that could materially reduce PEF's costs required by the CAIR and CAMR.

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an integrated strategy to comply with the CAIR and CAMR through the ECRC. PEF is developing an integrated compliance strategy for the CAIR and CAMR rules because NOx and SO_2 controls are effective in reducing mercury emissions. Program costs for 2005 were approximately $2 million for preliminary engineering activities and strategy development work necessary to determine our integrated compliance strategy. PEF currently projects to spend approximately $53 million in capital costs to comply with the CAIR and CAMR programs in 2006. These costs may increase or decrease depending upon the results of the engineering and strategy development work. Among other things, subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates could require acceleration of some projects and therefore result in additional costs in 2006.

CLEAN AIR VISIBILITY RULE

On June 15, 2005, the EPA issued the final Clean Air Visibility Rule (CAVR). The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas. To help restore visibility in those areas, states must require the identified facilities to install Best Available Retrofit Technology (BART) to control their emissions. Depending on the approach taken by the states, the reductions associated with BART would begin to take effect in 2014. CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. We expect that our compliance plans to comply with the CAIR and CAMR will fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress on improving visibility. PEC's BART-eligible units are Asheville Unit No. 1 and No. 2, Roxboro Unit No. 1, No. 2 and No. 3, and Sutton Unit No. 2. PEF's BART-eligible units are Anclote Unit No. 1, Bartow Unit No. 3, and Crystal River Unit No. 1 and No. 2. The outcome of this matter cannot be predicted.

NORTH CAROLINA ATTORNEY GENERAL PETITION UNDER SECTION 126 OF THE CLEAN AIR ACT

In March 2004, the North Carolina Attorney General filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force coal-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet national air quality standards for ozone and particulate matter. On August 1, 2005, the EPA issued a proposed response denying the petition. The EPA's rationale for denial is that compliance with CAIR will reduce the emissions from surrounding states sufficiently to address North Carolina's concerns. The EPA must take final action by March 15, 2006. The outcome of this matter cannot be predicted.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

On December 21, 2005, the EPA announced proposed changes to the NAAQS for particulate matter. The EPA proposed to lower the 24-hour standard for particulate matter less than 2.5 microns in diameter from 65 micrograms per cubic meter to 35 micrograms per cubic meter. In addition, the EPA proposed to establish a new 24-hour standard of 70 micrograms per cubic meter for particulate matter that is between 2.5 and 10 microns in diameter. The EPA also proposed to eliminate the current standards for particulate matter less than 10 microns in diameter. The EPA is scheduled to finalize the standards by September 27, 2006. The changes could ultimately result in increased costs for installation of additional pollution controls at facilities operated by PEC and PEF. The outcome of this matter cannot be predicted.

C. Water Quality

As a result of the operation of certain control equipment needed to address the air quality issues outlined above, new wastewater streams may be generated at the affected facilities. Integration of these new wastewater streams into the existing wastewater treatment processes may result in permitting, construction and treatment requirements imposed on the Utilities in the immediate and extended future.

Section 316(b) of the Clean Water Act requires assessment of the environmental effect of withdrawal of water at our facilities. We are conducting studies and currently estimate that total compliance costs through 2010 to meet Section 316(b) requirements of the Clean Water Act will be approximately $70 million to $95 million, of which an immaterial amount has been incurred through December 31, 2005. The range includes approximately $5 million to $10 million at PEC and approximately $65 million to $85 million at PEF.

The majority of compliance costs associated with water quality requirements for PEF are eligible for consideration for recovery through the ECRC. The outcome of future petitions for recovery through the ECRC cannot be predicted.

D. Other Environmental Matters

GLOBAL CLIMATE CHANGE

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other greenhouse gases. The treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol, and the Bush administration has stated it favors voluntary programs. There are proposals to address global climate change that would regulate CO_2 and other greenhouse gases. Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol and some additional proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. We have articulated principles that we believe should be incorporated into any global climate change policy. While the outcome of this matter cannot be predicted, we are taking voluntary action on this important issue as part of our commitment to environmental stewardship and responsible corporate citizenship.

In a decision issued July 15, 2005, a three-judge panel of the U.S. Court of Appeals for the District of Columbia Circuit denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions under the Clean Air Act. In a 2-1 decision, the court held that the EPA administrator properly exercised his discretion in denying the request for regulation. Officials from five states and the District of Columbia asked the full U.S. Court of Appeals for the D.C. Circuit to review the decision made by the three-judge panel. On December 2, 2005, the U.S. Court of Appeals denied the request for rehearing. On March 2, 2006, the petitioners filed a petition for a writ of certiorari with the

U.S. Supreme Court, seeking a review of the U.S. Court of Appeals decision. The outcome of this matter cannot be predicted.

In 2005, we initiated a study to assess the impact of constraints of CO_2 and other air emissions. We plan to issue this report by March 31, 2006. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act.

23. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2005, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions)	2006	2007	2008	2009	2010	Thereafter
Fuel	$2,786	$2,287	$1,031	$695	$268	$1,165
Purchased power	471	477	448	414	364	4,308
Construction obligations	74	28	–	–	–	–
Other purchase obligations	89	90	76	64	41	232
Total	$3,420	$2,882	$1,555	$1,173	$673	$5,705

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $3.070 billion, $2.033 billion and $1.645 billion for 2005, 2004 and 2003, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (qualifying facilities or QFs) with expiration dates ranging from 2006 to 2025. These purchased power contracts generally provide for capacity and energy payments.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and Power Agency, PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, Harris. In 1993, PEC and Power Agency entered into an agreement to restructure portions of their contracts covering power supplies and interests in jointly owned units. Under the terms of the 1993 agreement, PEC increased the amount of capacity and energy purchased from Power Agency's ownership interest in Harris, and the buyback period was extended six years through 2007. The estimated minimum annual payments for these purchases, which reflect capacity and energy costs, total approximately $34 million. These contractual purchases totaled $37 million, $39 million and $36 million for 2005, 2004 and 2003, respectively.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW of capacity through 2009 with estimated minimum annual payments of approximately $44 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $71 million, $62 million and $66 million for 2005, 2004 and 2003, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $44 million, $42 million and $37 million in 2005, 2004 and 2003, respectively.

PEC has various pay-for-performance contracts with QFs for approximately 354 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $112 million in 2005, $90 million in 2004 and $113 million in 2003.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2015. Total purchases, for both energy and capacity, under these agreements amounted to $175 million, $128 million and $126 million for 2005, 2004 and 2003, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $64 million annually through 2009, $54 million for 2010 and $38 million annually thereafter through 2015.

PEF has ongoing purchased power contracts with certain QFs for 812 MW of capacity with expiration dates ranging from 2006 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the qualifying facilities meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the generating capacity of each of the facilities. All commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $262 million, $247 million and $244 million for 2005, 2004 and 2003, respectively. At December 31, 2005, minimum expected future capacity payments under these contracts were $279 million, $289 million, $297 million, $262 million and $267 million for 2006 through 2010, respectively, and $3.6 billion thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost recovery clause.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007, to April 30, 2027. The total cost to PEF associated with the agreements is approximately $4.0 billion. The transactions are subject to several conditions precedent, some of which have been satisfied, which include obtaining the FPSC's approval of the agreements, the completion and commencement of operation of the necessary related expansions to SNG's and FGT's respective natural gas pipeline systems, and other standard closing conditions. Due to the conditions in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table presented above.

In January 2006, PEF entered into a conditional contract with Gulfstream Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008, through December 31, 2031. The total cost to PEF associated with this agreement is approximately $1.0 billion. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions. Due to the timing of this agreement, the estimated costs associated with this agreement are not included in the contractual cash obligations table presented above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $91 million, $108 million and $158 million for 2005, 2004 and 2003, respectively. Total purchases under various combustion turbine construction obligations were $5 million and $21 million for 2004 and 2003, respectively. We have purchase obligations related to various plant capital projects at the Hines Energy Complex. Total payments under these contracts were $91 million, $102 million and $137 million for 2005, 2004 and 2003, respectively. Our future obligations under these contracts are $74 million for 2006 and $28 million for 2007.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $97 million, $58 million and $31 million for 2005, 2004 and 2003, respectively.

On December 31, 2002, PEC and PVI entered into a contractual commitment to purchase at least $11 million and $4 million, respectively, of capital parts by December 31, 2010. During 2005, 2004 and 2003, no capital parts have been purchased under this contract.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $13 million for 2005, $17 million for 2004 and $3 million for 2003. Future purchase obligations are $7 million for 2006.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $8 million, $11 million and $3 million for 2005, 2004 and 2003, respectively. Future obligations under these contracts are $14 million, $11 million, $16 million, $14 million and $19 million for 2006 through 2010, respectively, with approximately $74 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $34 million for 2005. Future obligations under these contracts are $20 million and $25 million in 2006 and 2007, respectively, and $6 million in 2008 and 2009.

PVI has purchase obligations with two counterparties for pipeline capacity through 2018 and 2028. Payments under these arrangements were $15 million, $13 million and $6 million for 2005, 2004 and 2003, respectively. Future obligations under these contracts are approximately $16 million for 2006 through 2010 and approximately $117 million payable thereafter.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $48 million, $57 million and $54 million for 2005, 2004 and 2003, respectively. Our purchased power expense under agreements classified as operating leases were approximately $14 million in 2005, $25 million in 2004 and $5 million in 2003.

Assets recorded under capital leases at December 31 consisted of:

(in millions)	**2005**	2004
Buildings	**$30**	$30
Equipment and other	**27**	2
Less: Accumulated amortization	**(12)**	(11)
Total	**$45**	$21

At December 31, 2005, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

(in millions)	Capital	Operating
2006	$4	$76
2007	4	88
2008	4	88
2009	4	85
2010	4	71
Thereafter	21	298
	41	$706
Less amount representing imputed interest	(12)	
Present value of net minimum lease payments under capital leases	$29	

In 2003, we entered into a new operating lease for a building, for which minimum annual rental payments are included in the table above. The lease terms provide for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2005, PEF entered into an agreement for a new capital lease beginning in 2007 for a building that is currently under construction. The lease calls for annual payments of approximately $6 million from 2007 through 2026 for a total of approximately $110 million. The lease term provides for no payments during the last 20 years of the lease.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases for 2006 through 2010 are approximately $40 million, $24 million, $17 million, $13 million and $4 million, respectively, with $24 million receivable thereafter. Rents received under these operating leases totaled $66 million, $60 million and $45 million for 2005, 2004 and 2003, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals under noncancelable leases are $10 million for 2006 and none thereafter. Rents received are contingent upon usage and totaled $31 million, $32 million and $31 million for 2005, 2004 and 2003, respectively.

PEF's rents received are based on a fixed minimum rental where price varies by type of equipment and totaled $63 million for 2005 and 2004 and $56 million for 2003. Minimum rentals receivable (excluding streetlights) under noncancelable leases for 2006 is $5 million and none thereafter. Streetlight rentals were $42 million, $40 million and $38 million for 2005, 2004 and 2003, respectively. Future streetlight rentals would approximate 2005 revenues.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN No. 45). These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes (See Note 19). Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2005, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2005, we have issued guarantees and indemnifications of certain legal, tax and environmental matters to third parties in connection with sales of businesses and for timely payment of obligations in support of our nonwholly owned synthetic fuel operations. Related to the sales of businesses, the notice period extends until 2012 for the majority of matters provided for in the indemnification provisions. For matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain environmental indemnifications have no limitations as to time or maximum potential future payments. Other guarantees and indemnifications have an estimated maximum exposure of approximately $152 million. Additionally, in 2005 PEC entered into a contract with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a $16 million liability related to this indemnification (See Note 22B). At December 31, 2005, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $41 million. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

In addition, the Parent has issued $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 24).

D. Other Commitments and Contingencies

1. SPENT NUCLEAR FUEL MATTERS

Pursuant to the Nuclear Waste Policy Act of 1982, the predecessors to the Utilities entered into contracts with the DOE under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Our damages due to the DOE's breach will be significant, but have yet to be determined. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

The DOE and the Utilities have agreed to a stay of the lawsuit, including discovery. The parties agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been or are expected to be presented in the trials or appeals that are currently scheduled to occur during 2006. Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The EPA has not scheduled a date for issuance of revised proposed standards. The DOE originally planned to submit a license application to the NRC to construct the

Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and has not provided a new target date for submission of the license application. Congress approved $450 million for fiscal year 2006 for the Yucca Mountain project, approximately $201 million less than requested by the DOE. The DOE has acknowledged that a working repository will not be operational until sometime after 2010, but the DOE has not identified a new target date. The Utilities cannot predict the outcome of this matter.

On February 27, 2004, PEC requested to have its license for the Independent Spent Fuel Storage Installation at Robinson extended by 20 years with an exemption request for an additional 20-year extension. Its current license expires in August 2006 and on March 30, 2005, the NRC issued a 40-year license renewal.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at Robinson and Brunswick, PEC's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEC's system through the expiration of the operating licenses for all of PEC's nuclear generating units.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at PEF's nuclear unit, CR3, PEF's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEF's system through the expiration of the operating license for CR3.

2. SYNTHETIC FUEL MATTERS

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that own facilities that produce coal-based solid synthetic fuel as defined under Section 29 of the Code (Section 29). The production and sale of the synthetic fuel from these facilities qualify for tax credits under Section 29/45K if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the coal used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuel facilities entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuel produced and sold by these plants.

On August 8, 2005, the Energy Policy Act of 2005 (EPACT) was signed into law. This new federal law contains key provisions affecting the electric power industry, including the redesignation of the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K). The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are currently carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit was effective on January 1, 2006, and removes the regular federal income tax liability limit on synthetic fuel production and subjects the credits to a 20-year carry forward period. This provision would allow us to produce synthetic fuel to a higher level than we have historically produced should we choose to do so.

Total Section 29 credits generated through December 31, 2005 (including those generated by Florida Progress prior to our acquisition), are approximately $1.7 billion, of which $819 million has been used to offset regular federal income tax liability and $922 million is being carried forward as deferred alternative minimum tax credits. The current synthetic fuel tax credit program expires at the end of 2007.

IRS Proceedings

In July 2004, we were notified that the IRS field auditors anticipated taking an adverse position regarding the placed-in-service date of the Earthco facilities. On October 29, 2004, we received the IRS field auditors' preliminary report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and proposing that the tax credits generated by those facilities be disallowed.

During October 2005, we and the IRS field auditors filed briefs with the National Office for the purpose of receiving technical advice on whether our Earthco facilities were placed in service prior to July 1, 1998, in order to determine if our synthetic fuel tax credits are allowable under Section 29 of the Internal Revenue Code. During February 2006, the IRS field auditors verbally informed us that the IRS National Office concluded that our four Earthco synthetic fuel facilities met the placed-in-service requirement. The IRS field auditors also indicated that, once they receive written confirmation of the National Office's conclusion, the IRS field auditors will close their audit without any disallowance of tax credits. On February 28, 2006, we received our copy of the National Office Technical Advice Memorandum that concludes that the Earthco facilities met the placed-in-service requirement.

Permanent Subcommittee

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29. The investigation is examining the utilization of the credits, the nature of the technologies and fuels created, the use of the synthetic fuel and other aspects of Section 29 and is not specific to our synthetic fuel operations. Progress Energy provided information in connection with this investigation. We cannot predict the outcome of this matter.

Impact of Crude Oil Prices

Although the Section 29/45K tax credit program is expected to continue through 2007, recent market conditions, world events and catastrophic weather events have increased the volatility and level of oil prices that could limit the amount of those credits or eliminate them entirely for the years following 2005. This possibility is due to a provision of Section 29 that provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold price (the Threshold Price), the amount of Section 29/45K tax credits is reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. Synthetic fuel is not economical to produce absent the associated tax credits.

If the Annual Average Price falls between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits are reduced will depend on where the Annual Average Price falls in that continuum. For example, for 2004, the Threshold Price was $51.35 per barrel and the Phase-out Price was $64.47 per barrel. If the Annual Average Price had been $57.91 per barrel, there would have been a 50 percent reduction in the amount of Section 29 tax credits for that year.

The secretary of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency (EIA). Because the EIA publishes its information on a three-month lag, the secretary of the Treasury finalizes the calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2005 is expected to be published in early April 2006.

We estimate that the 2005 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $65 per barrel, based on an estimated 2005 inflation adjustment. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding monthly New York Mercantile Exchange (NYMEX) settlement price for light sweet crude oil. Through December 31, 2005, the average NYMEX contract settlement price for light sweet crude oil was $55 per barrel. Assuming that the $5 average differential between the Domestic Crude Oil First Purchases Price published by the EIA and the NYMEX settlement price continued through December 31, 2005, we do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits in 2005.

We estimate that the 2006 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $66 per barrel, based on estimated inflation adjustments for 2005 and 2006. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding monthly NYMEX settlement price for light sweet crude oil. As of January 31, 2006, the average NYMEX futures price for light sweet crude oil for calendar year 2006 was $69 per barrel. Based upon the estimated 2006 Threshold Price and Phase-out Price, if oil prices for 2006 remained at the January 31, 2006, average futures price level of $69 per barrel for the entire year in 2006, we currently estimate that the synthetic fuel tax credit amount for 2006 would be reduced by approximately 75 percent to 85 percent. Therefore, the estimated value of 2006 tax credits of approximately $27 per ton would be reduced to approximately $4 to $7 per ton for any synthetic fuel produced in 2006.

In November 2005, the U.S. Senate passed Senate Bill 2020, The Tax Relief Act of 2005, which includes proposed modifications to the Section 29/45K synthetic fuel tax credit program. This legislation would provide synthetic fuel producers with additional certainty around future synthetic fuel production decisions. The proposed modifications include amendments of the phase-out calculation and the annual inflation adjustment for the value of the synthetic fuel tax credits. Under Senate Bill 2020, the Annual Average Price, Threshold Price and the Phase-out Price for 2006 and 2007 would be based on the calculated amounts for the previous calendar year. In addition, the annual inflation adjustment for the synthetic fuel tax credits for 2005, 2006 and 2007 would be eliminated. The U.S. House version of the Tax Reconciliation bill does not include these same provisions. The differences in the Senate and House versions of the bill will be reconciled in conference. We cannot predict with any certainty the likelihood of this legislation passing.

As noted above, we do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits related to synthetic fuel production in 2005. Therefore, if the provisions of Senate Bill 2020 regarding changes to the Section 29/45K synthetic fuel tax credit program were enacted into law, there would be no phase-out of these tax credits in calendar year 2006. However, we cannot predict with any certainty the price of oil for 2006 or 2007 and, therefore, we cannot predict what impact, if any, this proposed legislation would have on the value of tax credits in 2007.

Our future synthetic fuel production levels for 2006 and 2007 remain uncertain because we cannot predict with any certainty the Annual Average Price of oil for 2006 or 2007 or the likelihood of legislation modifying the phase-out calculation being enacted into law. If oil prices for 2006 remained at the January 31, 2006, average futures price level of $69 per barrel for the entire year in 2006, it is unlikely that we would produce significant amounts of synthetic fuel in 2006 and could potentially forfeit credits associated with any 2006 synthetic fuel production. This could have a material adverse impact on our results of operations. We will continue to monitor the level of oil prices and retain the ability to adjust production based on future oil price levels.

Due to the significant uncertainty surrounding our synthetic fuel production in 2006 and 2007 based on the current level of oil prices, we evaluated our synthetic fuel and other related operating long-lived assets for impairment during the third quarter and fourth quarter of 2005. We determined that no impairment of these assets was required. However, an increase in oil prices or a decrease in future synthetic fuel production and cash flows could require additional impairment evaluations in the future, which could result in a future impairment of these assets, which have total carrying values as of December 31, 2005, of approximately $111 million. The majority of these assets will be fully depreciated by the end of 2007, the scheduled end of the synthetic fuel tax credit program. The outcome of this matter cannot be determined.

Sale of Partnership Interest

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona, one of our synthetic fuel facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gains from the sales will be recognized on a cost recovery basis as the facility produces and sells synthetic fuel and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectability is reasonably assured. Gain recognition is dependent on the synthetic fuel production qualifying for Section 29 tax credits and the value of such tax credits as discussed above. Until the gain recognition criteria are met, gains from selling interests in Colona will be deferred. It is possible that gains will be deferred in the first, second and/or third quarters of each year until there is persuasive evidence that no tax credit phase-out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters in a calendar year. In the event that the synthetic fuel tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuel tax credits, the amount of proceeds realized from the sale could be significantly impacted. We recognized a pre-tax gain on monetization of $30 million during 2005 based on the remote possibility of any phase-out of the synthetic fuel tax credits in 2005. A portion of this gain had been deferred through the third quarter of 2005.

Contingent Royalty Payments

We have certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties). The related agreements and their amendments require the payment of minimum annual royalties of approximately $7 million for each plant through 2007. We recorded a liability (included in other liabilities and deferred credits on the Consolidated Balance Sheets) and a deferred asset (included in other assets and deferred debits in the Consolidated Balance Sheets), each of approximately $50 million and $73 million at December 31, 2005 and 2004, respectively, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2005 and 2004, the portions of the asset and liability recorded that were classified as current were approximately $26 million. The deferred asset will be amortized to expense each year as synthetic fuel sales are made. The maximum amounts payable under these agreements remain unchanged. Future expected annual minimum royalty payments are approximately $26 million for 2006 and 2007. We have exercised our right under the related agreements to escrow those payments if certain conditions in the agreements were met, as more fully described below.

On May 15, 2005, the original owners of the Earthco synthetic fuel facilities filed suit in New York state court alleging breach of contract against the Progress Fuels subsidiaries that purchased the Earthco facilities (Progress Fuels Subsidiaries). The plaintiffs also named us as a defendant. The plaintiffs allege that periodic payments due to them under the sales arrangement with the Progress Fuels Subsidiaries are being improperly withheld and escrowed. The Progress Fuels Subsidiaries believe that the parties' agreements allow for the payments to be escrowed in the event of an audit, investigation or other proceeding under which the IRS can disallow the tax credits associated with the Earthco facilities. They also believe that the agreements allow for the use of such escrowed amounts to satisfy any potential disallowance of tax credits that arises out of such an event. Currently, the escrowed amount in question is $97 million, which reflects periodic payments that would have been paid to the plaintiffs beginning April 30, 2003, through January 31, 2006. This amount will increase as future periodic payments are made to the escrow, which would otherwise have been payable to the plaintiffs. Plaintiffs filed a partial summary judgment motion in December 2005 seeking payment of the escrowed money. The Progress Fuels Subsidiaries oppose the motion and will file opposition papers, which are not yet due. The parties are now engaged in discovery.

In addition, a number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global LLC (Global), Earthco, certain affiliates of Earthco (collectively the Earthco Sellers), EFC Synfuel LLC (which is owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC, Solid Fuel LLC, Ceredo Synfuel LLC, Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted that pursuant to the Asset Purchase Agreement it is entitled to an interest in two synthetic fuel facilities currently owned by the Progress Affiliates, and an option to purchase additional interests in the two synthetic fuel facilities.

The first suit, U.S. Global LLC v. Progress Energy, Inc. et al., was filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case). The Florida Global Case asserts claims for breach of the Asset Purchase Agreement and other contract and tort claims related to the Progress Affiliates' alleged interference with Global's rights under the Asset Purchase Agreement. The Florida Global Case requests an unspecified amount of compensatory damages, as well as declaratory relief. Following briefing and argument on a number of dispositive motions on successive versions of Global's complaint, on August 16, 2004, the Progress Affiliates answered the Fourth Amended Complaint by generally denying all of Global's substantive allegations and asserting numerous affirmative defenses. The parties are currently engaged in discovery in the Florida Global Case.

The second suit, Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC, was filed by the Progress Affiliates in the Superior Court for Wake County, N.C., seeking declaratory relief consistent with our interpretation of the Asset Purchase Agreement (the North Carolina Global Case). Global was served with the North Carolina Global Case on April 17, 2003.

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss and entered an order staying the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the Superior Court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal.

The Progress Affiliates believe that the parties' agreements allow for the payments due to Global to be escrowed in the event of an audit, investigation or other proceeding under which the IRS can disallow the tax credits and also allow for the use of such escrowed amounts to satisfy any potential disallowance of tax credits that arises out of such an event. Currently, the escrowed amount in question is $37 million, which reflects periodic payments that would have been paid to the plaintiffs beginning April 30, 2003, through January 31, 2006. This amount will increase as future periodic payments are made to the escrow that would otherwise have been payable to the plaintiffs.

We cannot predict the outcome of these matters, but will vigorously defend against the allegations.

3. FRANCHISE MATTERS

PEF has largely resolved its outstanding franchise matters. In August 2005, the cities of Edgewood, Fla. (1,400 customers), and Maitland, Fla. (7,000 customers), approved new 30-year electric utility franchise agreements with PEF. In November 2005, the 2,500 customer town of Belleair, Fla., voted to reject a referendum to municipalize, but has not yet signed a new utility franchise agreement with PEF. As previously noted, in accordance with the terms of an arbitration panel's award issued in May 2003 and after satisfying regulatory and operational requirements, Winter Park acquired from PEF the electric distribution system that serves Winter Park (14,000 customers) and PEF transferred the distribution system to Winter Park on June 1, 2005. In addition, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option (See Note 7C).

4. OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures in accordance with SFAS No. 5 to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

24. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the condensed consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The yearly interest expense is $21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2005, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN No. 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements and resulted in recording an additional equity investment in the Trust of approximately $9 million, an increase in outstanding debt of approximately $8 million and a gain of approximately $1 million relating to the cumulative effect of a change in accounting principle. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$3,955	$3,990	$7,945
Diversified business	–	1,496	667	2,163
Total operating revenues	–	5,451	4,657	10,108
Operating expenses				
Utility				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	334	588	922
Taxes other than on income	4	279	177	460
Other	–	(26)	(11)	(37)
Diversified business				
Cost of sales	–	1,338	737	2,075
Depreciation and amortization	–	79	73	152
Other	–	41	33	74
Total operating expenses	16	4,914	3,893	8,823
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Other income (expense), net	66	(4)	(51)	11
Interest charges, net	300	178	162	640
Income (loss) from continuing operations before income tax and minority interest	634	355	(333)	656
Income tax (benefit) expense	(63)	(40)	58	(45)
Minority interest in subsidiaries' loss, net of tax	–	(26)	–	(26)
Income (loss) from continuing operations	697	421	(391)	727
Discontinued operations, net of tax	–	(47)	16	(31)
Cumulative effect of changes in accounting principles, net of tax	–	–	1	1
Net income (loss)	$697	$374	$(374)	$697

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$3,525	$3,628	$7,153
Diversified business	–	1,125	247	1,372
Total operating revenues	–	4,650	3,875	8,525
Operating expenses				
Utility				
Fuel used in electric generation	–	1,175	836	2,011
Purchased power	–	567	301	868
Operation and maintenance	10	630	835	1,475
Depreciation and amortization	–	281	597	878
Taxes other than on income	(2)	254	173	425
Other	–	(2)	(11)	(13)
Diversified business				
Cost of sales	–	981	198	1,179
Depreciation and amortization	–	78	79	157
Other	–	17	84	101
Total operating expenses	8	3,981	3,092	7,081
Equity in earnings of consolidated subsidiaries	940	–	(940)	–
Other income (expense), net	65	(4)	(59)	2
Interest charges, net	295	162	171	628
Income (loss) from continuing operations before income tax and minority interest	702	503	(387)	818
Income tax (benefit) expense	(57)	61	102	106
Minority interest in subsidiaries' loss, net of tax	–	(17)	–	(17)
Income (loss) from continuing operations	759	459	(489)	729
Discontinued operations, net of tax	–	15	15	30
Net income (loss)	$759	$474	$(474)	$759

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2003

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$3,152	$3,589	$6,741
Diversified business	–	830	228	1,058
Total operating revenues	–	3,982	3,817	7,799
Operating expenses				
Utility				
Fuel used in electric generation	–	870	825	1,695
Purchased power	–	566	296	862
Operation and maintenance	19	640	762	1,421
Depreciation and amortization	–	307	576	883
Taxes other than on income	2	241	162	405
Other	–	–	(8)	(8)
Diversified business				
Cost of sales	–	736	193	929
Depreciation and amortization	–	62	64	126
Other	–	80	62	142
Total operating expenses	21	3,502	2,932	6,455
Equity in earnings of consolidated subsidiaries	1,039	–	(1,039)	–
Other income (expense), net	47	(8)	(76)	(37)
Interest charges, net	319	142	146	607
Income (loss) from continuing operations before income tax and minority interest	746	330	(376)	700
Income tax (benefit) expense	(36)	(112)	35	(113)
Minority interest in subsidiaries' income, net of tax	–	2	–	2
Income (loss) from continuing operations	782	440	(411)	811
Discontinued operations, net of tax	–	7	(12)	(5)
Cumulative effect of changes in accounting principles, net of tax	–	–	(24)	(24)
Net income (loss)	$782	$447	$(447)	$782

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$5,821	$8,621	$14,442
Current assets				
Cash and cash equivalents	239	241	126	606
Short-term investments	–	–	191	191
Receivables from affiliated companies	713	–	(713)	–
Deferred fuel cost	–	341	261	602
Assets of discontinued operations	–	107	2	109
Other current assets	22	1,069	1,139	2,230
Total current assets	974	1,758	1,006	3,738
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,594	–	(11,594)	–
Goodwill	–	2	3,717	3,719
Other assets and deferred debits	13	2,174	2,937	5,124
Total deferred debits and other assets	11,607	2,176	(4,940)	8,843
Total assets	$12,581	$9,755	$4,687	$27,023
Capitalization				
Common stock equity	$8,038	$3,039	$(3,039)	$8,038
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	38	5	43
Long-term debt, affiliate	–	440	(170)	270
Long-term debt, net	3,873	2,636	3,667	10,176
Total capitalization	11,911	6,187	522	18,620
Current liabilities				
Current portion of long-term debt	404	109	–	513
Notes payable to affiliated companies	–	315	(315)	–
Short-term obligations	–	102	73	175
Liabilities of discontinued operations	–	40	–	40
Other current liabilities	245	855	1,017	2,117
Total current liabilities	649	1,421	775	2,845
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	60	218	278
Regulatory liabilities	–	1,189	1,338	2,527
Accrued pension and other benefits	12	307	551	870
Other liabilities and deferred credits	9	591	1,283	1,883
Total deferred credits and other liabilities	21	2,147	3,390	5,558
Total capitalization and liabilities	$12,581	$9,755	$4,687	$27,023

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$5,882	$8,481	$14,363
Current assets				
Cash and cash equivalents	5	24	27	56
Short-term investments	–	–	82	82
Receivables from affiliated companies	1,415	5	(1,420)	–
Deferred fuel cost	–	89	140	229
Assets of discontinued operations	–	696	(11)	685
Other current assets	23	920	1,037	1,980
Total current assets	1,443	1,734	(145)	3,032
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,061	–	(11,061)	–
Goodwill	–	2	3,717	3,719
Other assets and deferred debits	16	2,068	2,846	4,930
Total deferred debits and other assets	11,077	2,070	(4,498)	8,649
Total assets	$12,520	$9,686	$3,838	$26,044
Capitalization				
Common stock equity	$7,633	$2,681	$(2,681)	$7,633
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	32	4	36
Long-term debt, affiliate	–	809	(539)	270
Long-term debt, net	4,449	2,052	2,750	9,251
Total capitalization	12,082	5,608	(407)	17,283
Current liabilities				
Current portion of long-term debt	–	49	300	349
Notes payable to affiliated companies	–	431	(431)	–
Short-term obligations	170	293	221	684
Liabilities of discontinued operations	–	186	–	186
Other current liabilities	245	931	688	1,864
Total current liabilities	415	1,890	778	3,083
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	64	584	648
Regulatory liabilities	–	1,362	1,292	2,654
Accrued pension and other benefits	10	248	375	633
Other liabilities and deferred credits	13	514	1,216	1,743
Total deferred credits and other liabilities	23	2,188	3,467	5,678
Total capitalization and liabilities	$12,520	$9,686	$3,838	$26,044

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$257	$515	$702	$1,474
Investing activities				
Gross utility property additions	–	(496)	(584)	(1,080)
Diversified business property additions	–	(190)	(16)	(206)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	702	5	(707)	–
Contributions to consolidated subsidiaries	(13)	–	13	–
Acquisition of intangibles	–	–	(3)	(3)
Other investing activities	1	(26)	(12)	(37)
Net cash provided (used) by investing activities	690	(292)	(1,515)	(1,117)
Financing activities				
Issuance of common stock	208	–	–	208
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Net decrease in short-term indebtedness	(170)	(191)	(148)	(509)
Retirement of long-term debt	(160)	(473)	69	(564)
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Changes in advances from affiliates	–	(101)	101	–
Contributions from parent	–	11	(11)	–
Other financing activities	(9)	40	1	32
Net cash (used) provided by financing activities	(713)	28	912	227
Cash used by discontinued operations				
Operating activities	–	(13)	–	(13)
Investing activities	–	(21)	–	(21)
Financing activities	–	–	–	–
Net increase in cash and cash equivalents	234	217	99	550
Cash and cash equivalents at beginning of year	5	24	27	56
Cash and cash equivalents at end of year	$239	$241	$126	$606

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$653	$571	$341	$1,565
Investing activities				
Gross utility property additions	–	(482)	(516)	(998)
Diversified business property additions	–	(150)	(19)	(169)
Nuclear fuel additions	–	–	(101)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	343	30	373
Purchases of available-for-sale securities and other investments	–	(569)	(2,565)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	–	569	2,679	3,248
Changes in advances to affiliates	27	(5)	(22)	–
Contributions to consolidated subsidiaries	(15)	–	15	–
Acquisition of intangibles	–	–	(1)	(1)
Other investing activities	–	(23)	(6)	(29)
Net cash provided (used) by investing activities	12	(317)	(506)	(811)
Financing activities				
Issuance of common stock	73	–	–	73
Proceeds from issuance of long-term debt, net	365	56	–	421
Net increase in short-term indebtedness	170	293	217	680
Retirement of long-term debt	(705)	(68)	(580)	(1,353)
Dividends paid on common stock	(558)	–	–	(558)
Dividends paid to parent	–	(340)	340	–
Changes in advances from affiliates	–	(209)	209	–
Contributions from parent	–	12	(12)	–
Other financing activities	(5)	13	(2)	6
Net cash (used) provided by financing activities	(660)	(243)	172	(731)
Cash provided (used) by discontinued operations				
Operating activities	–	44	–	44
Investing activities	–	(46)	–	(46)
Financing activities	–	–	–	–
Net increase in cash and cash equivalents	5	9	7	21
Cash and cash equivalents at beginning of year	–	15	20	35
Cash and cash equivalents at end of year	$5	$24	$27	$56

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2003

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$524	$517	$547	$1,588
Investing activities				
Gross utility property additions	–	(526)	(446)	(972)
Diversified business property additions	–	(302)	(146)	(448)
Nuclear fuel additions	–	(51)	(66)	(117)
Proceeds from sales of discontinued operations and other assets, net of cash divested	451	100	28	579
Purchases of available-for-sale securities and other investments	–	(441)	(3,351)	(3,792)
Proceeds from sales of available-for-sale securities and other investments	–	441	3,088	3,529
Changes in advances to affiliates	(327)	(16)	343	–
Contributions to consolidated subsidiaries	(411)	–	411	–
Acquisition of intangibles	–	–	(200)	(200)
Other investing activities	(1)	(15)	21	5
Net cash used in investing activities	(288)	(810)	(318)	(1,416)
Financing activities				
Issuance of common stock	304	–	–	304
Proceeds from issuance of long-term debt, net	–	935	604	1,539
Net decrease in short-term indebtedness	–	(258)	(438)	(696)
Retirement of long-term debt	–	(534)	(276)	(810)
Dividends paid on common stock	(541)	–	–	(541)
Dividends paid to parent	–	(301)	301	–
Changes in advances from affiliates	–	274	(274)	–
Contributions from parent	–	168	(168)	–
Other financing activities	–	–	16	16
Net cash (used) provided by financing activities	(237)	284	(235)	(188)
Cash provided (used) by discontinued operations				
Operating activities	–	123	–	123
Investing activities	–	(126)	–	(126)
Financing activities	–	–	–	–
Net decrease in cash and cash equivalents	(1)	(12)	(6)	(19)
Cash and cash equivalents at beginning of year	1	27	26	54
Cash and cash equivalents at end of year	$–	$15	$20	$35

25. SUBSEQUENT EVENT

On January 25, 2006, we signed a definitive agreement to sell PT LLC to Level 3 Communications, Inc. (Level 3) for a purchase price of approximately $137 million, with half of the proceeds in cash and half in Level 3 common stock. We expect to use net cash proceeds of $70 million from the sale of our interest in PT LLC to reduce debt.

The sale is expected to close by mid-2006, and is subject to various closing conditions customary to such transactions. We expect to report PT LLC as a discontinued operation in the first quarter of 2006. The carrying amounts for the assets and liabilities of the discontinued operations disposal group included in the Consolidated Balance Sheets as of December 31 were as follows:

(in millions)	2005	2004
Total current assets	$12	$16
Total property, plant and equipment, net	79	75
Total other assets	23	39
Total current liabilities	8	15
Total long-term liabilities	35	34
Minority interest	24	21
Total capitalization	47	60

26. QUARTERLY FINANCIAL DATA (UNAUDITED)

Results of operations for an interim period may not give a true indication of results for the year. In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Summarized quarterly financial data was as follows:

(in millions except per share data)	First[a][b]	Second[a][b]	Third[a][b]	Fourth[a][b]
2005				
Operating revenues	**$2,168**	**$2,295**	**$3,067**	**$2,578**
Operating income	**252**	**143**	**558**	**332**
Income from continuing operations before cumulative effect of changes in accounting principles	**104**	**7**	**459**	**157**
Net income	**93**	**(1)**	**450**	**155**
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	**0.43**	**0.03**	**1.86**	**0.63**
Net income	**0.38**	**(0.01)**	**1.82**	**0.62**
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	**0.43**	**0.03**	**1.85**	**0.63**
Net income	**0.38**	**(0.01)**	**1.81**	**0.62**
Dividends declared per common share	**0.590**	**0.590**	**0.590**	**0.605**
Market price per share				
High	**45.33**	**45.83**	**46.00**	**45.50**
Low	**40.63**	**40.61**	**41.90**	**40.19**
2004				
Operating revenues	$1,987	$2,085	$2,445	$2,008
Operating income	283	288	567	306
Income from continuing operations before cumulative effect of changes in accounting principles	102	145	287	195
Net income	108	154	303	194
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.42	0.59	1.18	0.81
Net income	0.45	0.63	1.25	0.80
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.42	0.59	1.18	0.81
Net income	0.45	0.63	1.24	0.80
Dividends declared per common share	0.575	0.575	0.575	0.590
Market price per share				
High	47.95	47.50	44.32	46.10
Low	43.02	40.09	40.76	40.47

[a] Operating results have been restated for discontinued operations.
[b] Certain amounts have been reclassified to conform with current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. First quarter 2005 includes $31 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative at PEF (See Note 17). Second quarter 2005 includes a $141 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 17). The 2004 amounts were restated for discontinued operations (See Notes 3A and 3B). Fourth quarter 2004 includes a $31 million after-tax gain on sale of natural gas assets (See Note 3E) and $90 million of Section 29 tax credits being recorded (See Note 23D). Third quarter 2004 includes reversal of $79 million of Section 29 tax credits (See Note 23D).

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

Years ended December 31 *(in millions, except per share data)*	2005	2004[a]	2003[a]	2002[a]	2001[a]
Operating results					
Operating revenues	**$10,108**	$8,525	$7,799	$7,258	$7,209
Income from continuing operations	**727**	729	811	584	728
Net income	**697**	759	782	528	542
Per share data					
Basic earnings					
Income from continuing operations	**$2.95**	$3.01	$3.42	$2.69	$3.56
Net income	**2.82**	3.13	3.30	2.43	2.65
Diluted earnings					
Income from continuing operations	**2.94**	3.00	3.40	2.68	3.55
Net income	**2.82**	3.12	3.28	2.42	2.64
Assets	**$27,023**	$26,044	$26,147	$24,378	$23,815
Capitalization					
Common stock equity	**$8,038**	$7,633	$7,444	$6,677	$6,004
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**43**	36	30	18	12
Long-term debt, net[b]	**10,446**	9,521	9,934	9,747	8,619
Current portion of long-term debt	**513**	349	868	275	688
Short-term obligations	**175**	684	4	695	942
Total capitalization and total debt	**$19,308**	$18,316	$18,373	$17,505	$16,358
Other financial data					
Return on average common stock equity (percent)	**8.91**	9.99	11.07	8.44	9.41
Ratio of earnings to fixed charges	**1.98**	2.22	2.01	1.57	1.93
Number of common shareholders of record	**64,899**	67,638	70,159	72,792	75,673
Book value per common share	**$32.35**	$31.39	$30.94	$28.73	$28.20
Dividends declared per common share	**$2.38**	$2.32	$2.26	$2.20	$2.14
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**52,306**	50,782	51,501	49,734	48,732
Nuclear	**30,120**	30,445	30,576	30,126	27,301
Hydro	**11,349**	9,695	7,819	8,522	6,644
Combustion turbines/combined cycle	**749**	802	955	491	245
Purchased	**14,566**	13,466	13,848	14,305	14,469
Total energy supply (Company share)	**109,090**	105,190	104,699	103,178	97,391
Joint-owner share[c]	**5,388**	5,395	5,213	5,258	4,886
Total system energy supply	**114,478**	110,585	109,912	108,436	102,277

[a] Operating results and balance sheet data have been restated for discontinued operations.
[b] Includes long-term debt to affiliated trust of $270 million at December 31, 2005, 2004 and 2003.
[c] Amounts represent co-owners' share of the energy supplied from the six generating facilities that are jointly owned.

We use ongoing earnings per share to evaluate our operations and to establish goals for management and employees. We believe this presentation is appropriate and enables investors to compare more accurately our ongoing financial performance over the periods presented. Ongoing earnings as presented here may not be comparable to similarly titled measures used by other companies. Reconciling adjustments from GAAP earnings to ongoing earnings are as follows:

December 31	2005	2004	2003
Ongoing earnings per share	**$3.33**	$2.96	$3.51
Contingent value obligation mark-to-market	**0.03**	0.04	(0.04)
Discontinued operations	**(0.13)**	0.12	(0.02)
Postretirement and severance charges	**(0.41)**	—	—
SRS litigation settlement	—	(0.12)	—
Gain on sale of natural gas assets	—	0.13	—
Cumulative effect of accounting changes	—	—	(0.10)
Impairments and one-time charges	—	—	(0.05)
Reported GAAP earnings per share	**$2.82**	$3.13	$3.30

CONTINGENT VALUE OBLIGATION (CVO) MARK-TO-MARKET

In connection with the acquisition of Florida Progress Corporation, we issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on after-tax cash flows above certain levels of four synthetic fuel facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVOs are debt instruments and, under GAAP, are valued at market value. Unrealized gains and losses from changes in market value are recognized in earnings. Since changes in the market value of the CVOs do not affect our underlying obligation, we do not consider the adjustment a component of ongoing earnings.

COAL MINE DISCONTINUED OPERATIONS

The coal mining operations are reported as discontinued operations due to our commitment to dispose of these assets, and therefore we do not view this activity as representative of our ongoing operations.

PROGRESS RAIL DISCONTINUED OPERATIONS

The operations of Progress Rail are reported as discontinued operations due to its sale in 2005, and therefore we do not believe this activity is representative of our ongoing operations.

NCNG DISCONTINUED OPERATIONS

The operations of NCNG are reported as discontinued operations due to its sale in 2003, and therefore we do not believe this activity is representative of our ongoing operations.

POSTRETIREMENT AND SEVERANCE CHARGES

As part of our cost-management initiative, we approved a workforce restructuring, which resulted in a reduction of approximately 450 positions. In connection with the cost-management initiative, we incurred charges related to estimated future payments for severance, postretirement and termination benefits that will be paid out over time to the 1,450 eligible employees who elected to participate in the voluntary enhanced retirement program. We do not expect to incur any similar charges in 2006. Due to the nonrecurring nature of the adjustment, we do not believe it is representative of our ongoing operations.

SRS LITIGATION SETTLEMENT

In June 2004, SRS, a subsidiary of ours, reached and recorded a charge for a settlement agreement in a civil suit. We do not believe this settlement charge is representative of our ongoing operations.

GAIN ON SALE OF NATURAL GAS ASSETS

In December 2004, we finalized the sale of certain gas-producing properties and related assets and recognized a gain. We do not believe this gain is representative of our ongoing operations.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

We recorded the cumulative effect of changes in accounting principles due to the adoption of new FASB accounting guidance. The impact to us was due primarily to new FASB guidance related to the accounting for certain contracts. Due to the nonrecurring nature of the adjustment, we do not believe it is representative of our ongoing operations.

IMPAIRMENTS AND ONE-TIME CHARGES

During 2003, we recorded after-tax impairments of our Affordable Housing portfolio. We do not believe these impairments are representative of our ongoing operations.

Notice of Annual Meeting

Progress Energy's 2006 annual meeting of shareholders will be held on May 10, 2006, at 10 a.m. in the Fletcher Opera Theater at the Progress Energy Center for the Performing Arts in Raleigh, N.C. A formal notice of the meeting with a proxy statement will be mailed to shareholders in early April.

Transfer Agent and Registrar Mailing Address

Progress Energy, Inc.
c/o Computershare Trust Company
250 Royall Street
Canton, MA 02021
Toll-free phone number: **1.866.290.4388**

Shareholder Information and Inquiries

Obtain information on your account 24 hours a day, seven days a week by calling our stock transfer agent's shareholder information line. This automated system features Progress Energy's common stock closing price, dividend information and stock transfer information. Call toll-free **1.866.290.4388.**

Other questions concerning stock ownership may be directed to Progress Energy's Shareholder Relations by calling **919.546.3014** or by writing to the following address:

Progress Energy, Inc.
Shareholder Relations
410 S. Wilmington Street
Raleigh, NC 27601-1849

Stock Listings

Progress Energy's common stock is listed and traded under the symbol PGN on the New York Stock Exchange in addition to regional stock exchanges across the United States.

Shareholder Programs

Progress Energy offers the Progress Energy Investor Plus Plan, a direct stock purchase and dividend reinvestment plan, and direct deposit of cash dividends to bank accounts for the convenience of shareholders. For information on these programs, contact Computershare or the company.

Proxy material, including the annual report, can be electronically delivered to shareholders. Electronic delivery provides immediate access to proxy material and allows Internet voting while saving printing and mailing costs. To take advantage of electronic delivery of proxy material, go to **econsent.com/pgn** and follow the instructions.

We also offer online access to shareholder accounts via the Internet. To obtain online access to your shareholder account, go to **computershare.com/equiserve.** If you have access to Progress Energy's annual report at your address, and do not want to receive a copy for your shareholder account, please call our transfer agent, Computershare, toll-free at **1.866.290.4388** to discontinue receiving annual reports by mail.

Securities Analyst Inquiries

Securities analysts, portfolio managers and representatives of financial institutions seeking information about Progress Energy should contact Robert F. Drennan Jr., manager, Investor Relations, at the corporate headquarters' address or call **919.546.7474.**

Additional Information

Progress Energy files periodic reports with the Securities and Exchange Commission that contain additional information about the company. Copies are available to shareholders upon written request to the company's treasurer at the corporate headquarters' address.

This annual report is submitted for shareholders' information. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

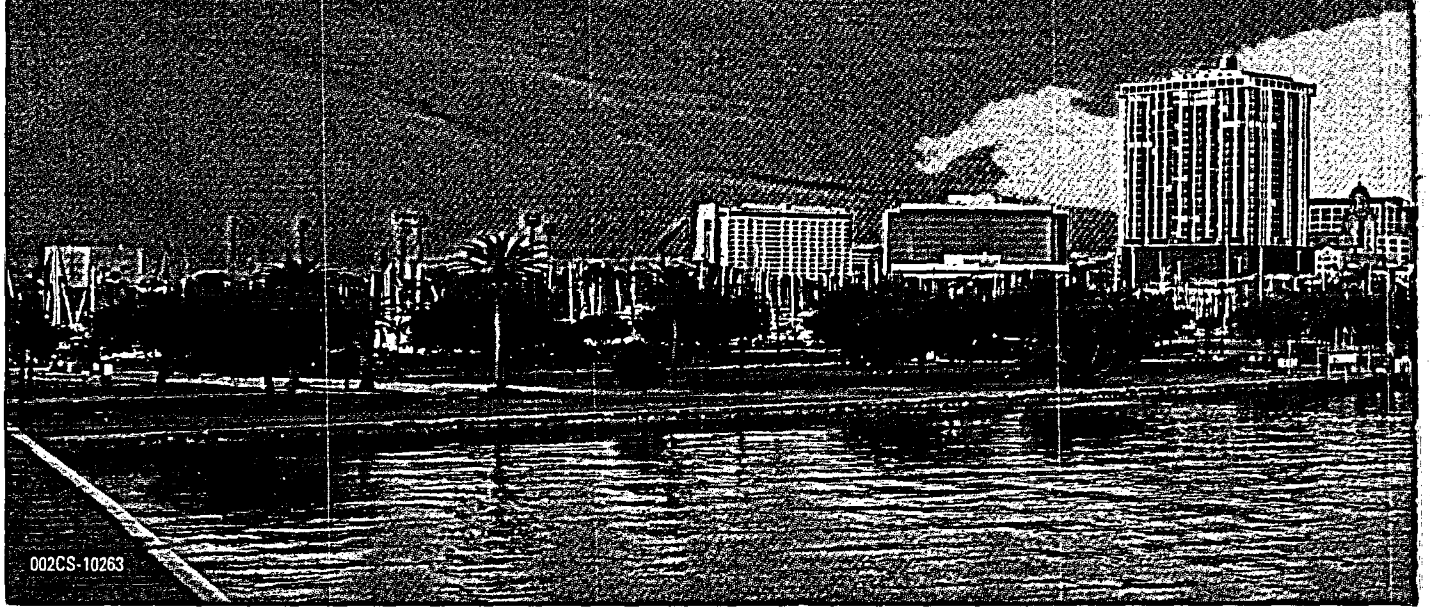
NYSE Certifications

Because Progress Energy's common stock is listed on the New York Stock Exchange ("NYSE"), our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of June 10, 2005. In addition, we have filed, as exhibits to the Annual Report on Form 10-K, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the Securities and Exchange Commission regarding the quality of our public disclosure.

Progress Energy

Progress Energy, Inc.
P.O. Box 1551
Raleigh, N.C. 27602-1551
progress-energy.com

St. Petersburg – Progress Energy Florida's headquarters and one of the state's most vibrant, growing cities.



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