BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

MINIMUM FILING REQUIREMENTS

SECTION F – MISCELLANEOUS SCHEDULES

Progress Energy

DOCUMENT NUMBER-DATE
04226 APR 29 05
FPSC-COMMISSION CLERK

Progress Energy Florida, Inc.
Docket # 050078-EI
Minimum Filing Requirements
Section F - Miscellaneous Schedules
Projected Test Year 2006

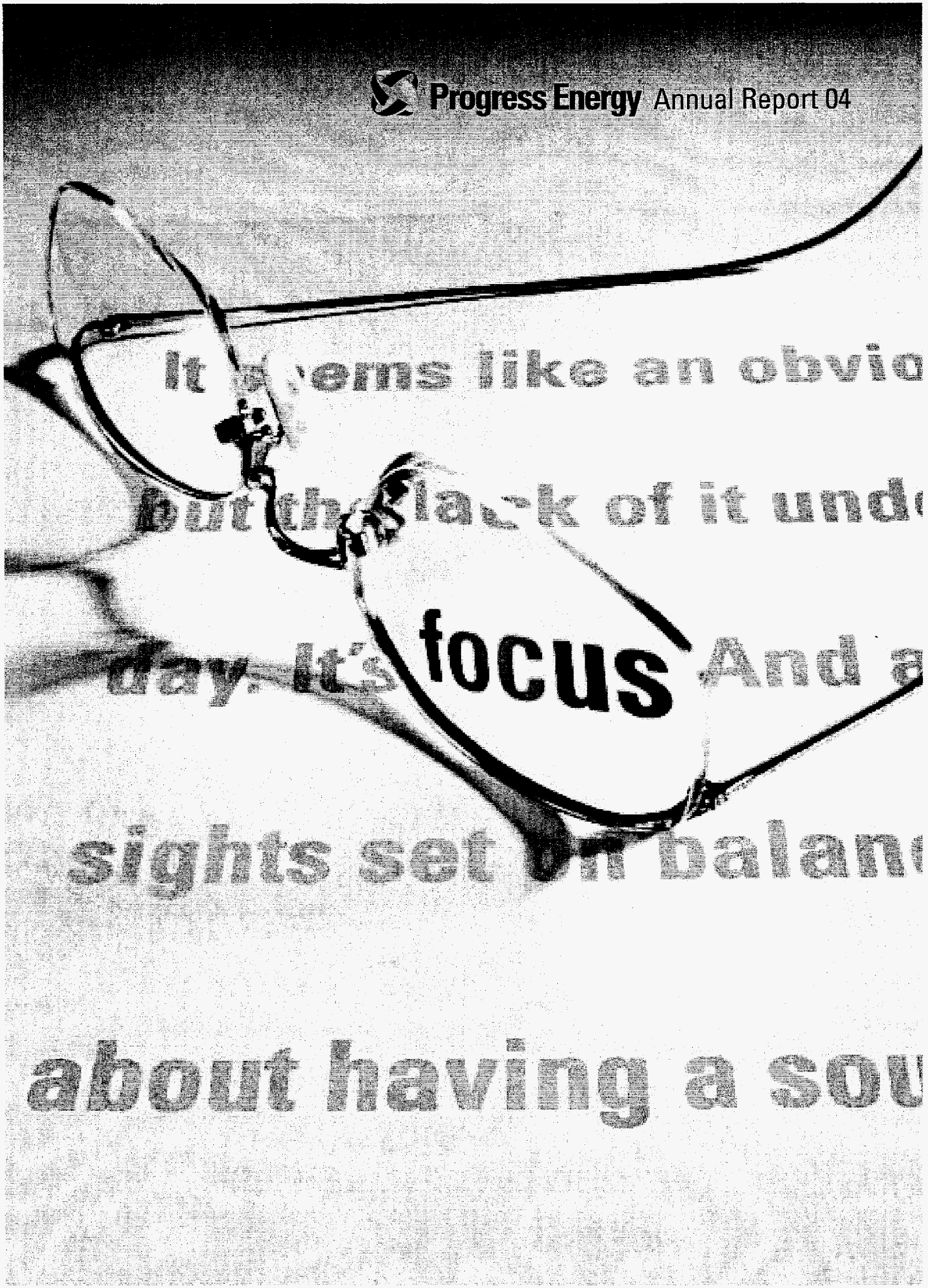
Table of Contents

Schedule	*Title*
F-1	Annual and Quarterly Report to Shareholders
F-2	SEC Reports
F-3	Business Contracts with Officers or Directors
F-4	NRC Safety Citations
F-5	Forecasting Models
F-6	Forecasting Models - Sensitivity of Output to Changes in Input Data
F-7	Forecasting Models - Historical Data
F-8	Assumptions
F-9	Public Notice

2005 Rate Case

MFRs

F Schedules



about having a sou

financial highlights

Years ended December 31 (in millions, except per share data)	**2004**	2003	2002
Financial Data			
Operating revenues	**$9,772**	$8,741	$8,091
Net income	**759**	782	528
Income from continuing operations	**753**	811	552
Ongoing earnings per common share*	**3.06**	3.56	3.81
Reported GAAP earnings per common share	**3.13**	3.30	2.43
Average common shares outstanding	**242**	237	217
Common Stock Data			
Return on average common stock equity (percent)	**9.99**	11.07	8.44
Book value per common share	**$31.26**	$30.94	$28.73
Market value per common share (closing)	**$45.24**	$45.26	$43.35

**See page 111 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*

It seems like an obvious ingredient for any business, but the lack of it undermines companies every day. It's **focus**. And at Progress Energy, it keeps our sights set on balanced long-term performance. It's about having a **sound strategy** for the future as well as **steady execution** today. It's promoting successful **economic development** to create tomorrow's opportunities. And it's investing in **community initiatives** that make our territory a more attractive, more healthy place to live. Our focus motivates us to look past what's obvious and into what's possible. And it's why we're confident in our **vision** for the future.

Robert B. McGehee – Chairman and Chief Executive Officer

Dear Fellow Shareholders:

Progress Energy kept a relentless focus on excellence and long-term value in 2004. We increased the dividend for the 17th consecutive year and for the 29th time in the last 30 years. And we entered 2005 with a clear vision of what we need to accomplish and a well-founded confidence in our ability to do it.

Even though the unprecedented series of hurricanes last year created serious problems for our customers and company in the short run, the fundamentals of our core business remain sound. Moreover, our employees once again proved how well they rise to any challenge.

Executing a Clear Strategic Plan – In 2004, our management team conducted an extensive analysis of our industry and our company. We developed a clear road map for the next three years and beyond that will reinforce our position as a buy-and-hold stock providing good value at modest risk.

We reaffirmed the basic strategic focus on our three core energy businesses: Progress Energy Carolinas and Progress Energy Florida – our electric utilities serving regulated markets – and Progress Ventures (excluding synthetic fuels), which serves competitive energy markets in the eastern United States.

Our strategic plan also includes selective asset sales to complete the restoration of our balance sheet. We sold our North Texas natural gas properties in December 2004 and have used the over $250 million in proceeds to retire debt. In February 2005, we reached a definitive agreement to sell Progress Rail, a subsidiary acquired in the 2000 merger. The $405 million in proceeds also will be used for debt reduction.

In addition, our plan calls for growing our core business earnings per share over the long term by 3 percent to 5 percent a year, which will support continued dividend growth. We know that consistent dividend growth is a major reason investors buy our stock.

Our strategy will help us maintain and enhance shareholder value as we make the transition beyond the federal synthetic-fuel tax program that expires at the end of 2007. In 2004, we resolved the federal tax audit issues with our Colona synthetic-fuel facilities, but, as of early 2005, we are still working with the Internal Revenue Service to resolve issues with the Earthco synthetic-fuel audit. While we feel good about our case, we can't predict the outcome.

(Letter continued inside)

Investing in Utilities and Controlling Costs – We continue to invest nearly $1 billion of capital each year in our two electric utilities to serve new retail customers and growing demand. We now have almost 3 million customers in our two service areas, which are among the most attractive locations in the country.

In 2004, we began building the third generating unit at our Hines Energy Complex in Polk County, Fla. The unit is scheduled for service in December 2005. Also last year, we received a 20-year license extension for our Robinson Nuclear Plant in Darlington County, S.C., and this year we will complete a four-year program to boost nuclear production capacity at our existing plants. In addition, we're expanding our transmission system and distribution facilities at both utilities to ensure continued reliability.

Cost management is central to our strategic plan. We began an initiative in late 2004 to eliminate $75 million to $100 million in projected growth of annual nonfuel operating costs by the end of 2007. As part of this effort, we launched a companywide organization study to be completed in 2005. It includes a streamlined management structure and a voluntary early retirement program.

Keeping an Eye on Results that Matter – At Progress Energy, we're staying focused on achieving five key results that matter for our long-term success:

- excellence in business operations
- loyal and satisfied customers
- good value to investors
- motivated and productive employees
- exemplary corporate citizenship

As important as it is to meet financial objectives and investor expectations, we must pay close attention to all of these vital areas. For example, in finding ways to reduce costs, we will not take short-sighted actions that compromise safety or service or the high-performance culture we're building here.

And we know it ultimately benefits us as well as our neighbors when we give back to the communities we serve. We do this by supporting a variety of community initiatives in education, the environment and economic development.

Building Momentum in 2005 – In addition to continuous improvement throughout the company, we are focused on these seven priorities in 2005:

- Entering 2006 with projected core business earnings-per-share growth that supports dividend growth for the 18th consecutive year
- Sustaining our record of excelling at the basics, including generation performance, service reliability, customer satisfaction and employee safety
- Implementing organization and process changes to eliminate $75 million to $100 million in projected nonfuel operating expenses by the end of 2007
- Reducing leverage and recovering our stable investment grade rating
- Making progress on the Internal Revenue Service tax audit of the Earthco synthetic-fuel plants
- Successfully resolving the Florida rate case and achieving timely recovery of our storm costs
- Negotiating a reasonable bargaining-unit contract in Florida

We're off to a good start in 2005. From operational performance to debt reduction and cost management, we are building positive momentum, and I expect that trend to continue.

As I reflect on my first year as chairman and CEO, I am grateful for all of your support. And in looking ahead, I am enthusiastic about Progress Energy's future. We understand who we are, what we do well and how to keep improving performance and adapting to change.

We know that our customers, investors and neighbors count on Progress Energy to perform to very high standards, day after day, year after year. I'm convinced we have the right people and focus to live up to that expectation.

Robert B. McGehee

Chairman and Chief Executive Officer

Identifying the best formula for long-term performance. We didn't earn our reputation overnight. Being known as a good value with reliable performance is a distinction Progress Energy has achieved with careful planning and unrelenting focus on our long-term goals. Chief among them is yearly dividend growth, something we've accomplished in 29 of the last 30 years, and a key objective of our business strategy.

In 2004, we laid out a strategic plan designed to guide us successfully through 2007 and position us well for the years beyond. It's a model that relies on our fundamental strengths to produce value over both the short and long term. We're maintaining our focus on our primary business – generating and distributing energy in both the regulated and competitive markets. Looking ahead, we've established an earnings objective of 3 percent to 5 percent annual growth for our three core businesses, including sustained but careful growth on the unregulated side of our business.

To accomplish these objectives, we've committed to investing nearly $1 billion each year in our infrastructure to improve our current distribution system, increase our overall generation capacity and support growing demand in our thriving territories. And we're well on our way to achieving our Progress Ventures earnings objectives through wholesale power contracts signed in 2004. We now serve 30 percent of the Georgia rural electrical cooperative market. That's 550,000 new end-use customers.

At Progress Energy, we firmly believe we're in the right position to achieve our goals in 2005. With unshakable focus, we will continue to grow our business and deliver greater value to our shareholders. After all, we have a reputation to uphold.

Even after 100 years in the business, we never stop generating new ideas and new ways to leverage our core strength. *(George Kerst, manager – Plant Production, and Paul Crimi, general manager – Combustion Turbine Operations, at our Hines Plant in Florida.)*

Progress Energy's average annual total return to shareholders over the last decade, based on stock price and reinvested dividends, is 11.1 percent.

In 2004, we improved our balance sheet by reducing our debt-to-capitalization ratio to 57.6 percent. We're on track to reach our goal of 55 percent debt.

Our investments in natural gas properties continue to yield solid returns. Progress Fuels provided approximately $180 million in net income in 2004.

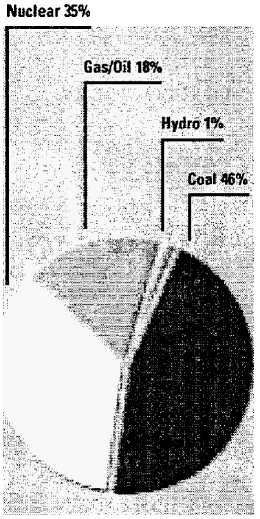
Annual Dividend Growth

We have a 17-year track record and a strategy to continue the trend.

Hurricanes Charley, Frances, Ivan and Jeanne crisscrossed Progress Energy territory. In total, we restored service to 3.4 million customers and earned a record fifth EEI Emergency Response Award for our efforts.

In 2004, 87 percent of Progress Energy customers gave us top ratings in measures of customer satisfaction and loyalty.

Our fossil generation and combustion turbine employees improved an already excellent safety record by 26 percent.



2004 Generation Fuel Mix
Our diverse generation mix helps us hedge against fluctuating fuel prices and keep our power supply as flexible as it is reliable.

Reliability is about more than the strength of our infrastructure. It's about the determination of the people who back it up. *(Mike Dodd, system transmission lineman, services a 230-kV transmission line.)*

Recognizing the opportunity to make a lasting impression. A strategy is nothing without execution. That's where thousands of Progress Energy employees come in, turning our long-term focus into action today. We know that what happens on any given day is part of a much bigger story, and a chance to have a lasting impact on the customers we serve and the value we deliver.

There's no greater testament to this focus – our determination to stay the course – than the unprecedented hurricane season of 2004, which brought our territories four major hurricanes in six weeks. Progress Energy employees responded with creativity and extraordinary collaboration to restore service to our customers quickly and safely each time. We know that it's often during short-lived circumstances that our customers form their most lasting opinions of us. So we don't take for granted the opportunity to boost customer satisfaction and loyalty.

Behind the scenes, our 38 plants operate seamlessly day in and day out, with the capacity to produce more than 24,000 megawatts of power for our nearly 3 million customers. Performance at our plants remains a top priority, and in response, our employees are delivering on their goals. In fact, our nuclear and fossil fleets continue to rank among the best in the nation in the areas of cost, production, reliability and safety.

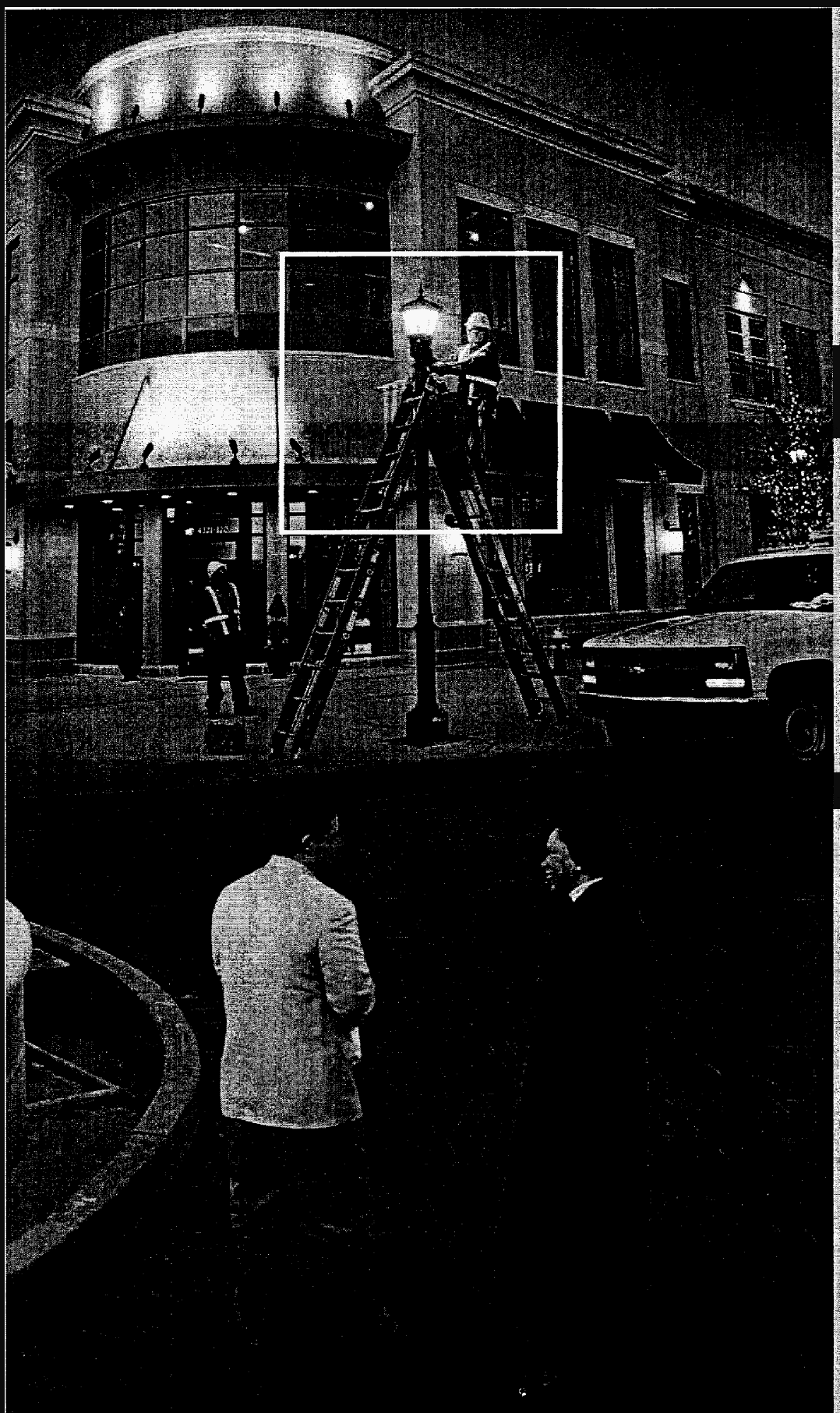
No doubt, our standards of operational excellence are high. But it's these standards that set us apart in extraordinary circumstances and ordinary ones. And by steadily achieving our goals, we'll continue to deliver performance to our customers and our shareholders alike.

Viewing growth as the catalyst for real momentum. No question, Progress Energy's territory is growing. Development – residential, commercial, industrial – is everywhere you look. But what we see is more than new subdivisions and businesses. We see the foundation of a prosperous future and increased value for our shareholders. That's why we've focused people and resources on the job of attracting new businesses and expanding existing ones. By all accounts, it's energy well spent.

Our customer base is growing at a rate of 2 percent to 3 percent annually – that's an average of 60,000 new customers every year. In Florida, high-tech industry is rapidly becoming a significant contributor to the state's economy, with several large companies relocating to the state in 2004. And over the next five years, the independent research firm Economy.com projects that Florida will rank fourth nationally in economic growth and fifth in population growth.

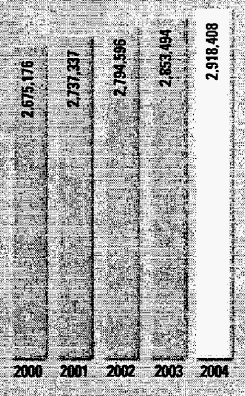
In the Carolinas, the pharmaceutical and health service industries saw significant growth in 2004, with more on the horizon. Thanks to this kind of sustainable development, Economy.com projects North Carolina to continue to rank among the fastest-growing states in the nation in population and new residential construction.

Economic development is about far more than creating new Progress Energy customers today. It's about creating the kind of lasting growth that triggers more of the same – helping other businesses expand and providing valuable opportunities for people in the cities and towns we serve. We're pursuing our own future, from the inside out.



Our economic development initiatives pave the way for growing businesses...and the new customers they bring. *(Hilda Pinnix-Ragland, vice president – Northern Region, and Bob Donaldson, account executive, with line & service technicians Garrett Lloyd and David Keyser at the recently opened North Hills complex in Raleigh, N.C.)*

- *In 2004, Progress Energy helped bring a total of $933 million in new capital investment and over 10,000 new jobs to our territories.*
- *For the third year in a row, Site Selection magazine has named Progress Energy to its list of "Top Utilities for Economic Development."*
- *The Minority Supplier Development Councils in Florida and the Carolinas named Progress Energy "Corporation of the Year." Our Supplier Diversity Program spending totaled $98 million in 2004.*



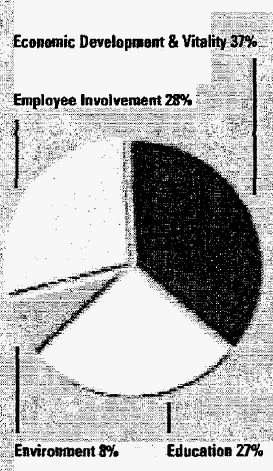
5-year Customer Growth

Our attractive territories make for a very attractive outlook.

In 2004, Progress Energy invested more than $11 million in community organizations through our local, corporate and foundation grant programs.

During our 2004 annual giving campaign, Progress Energy employees gave a total of $2.3 million in contributions, which will directly support programs in their local communities.

Progress Energy employees also donated more than 50,000 hours of community service in 2004. In last year's Relay For Life, 60 teams of employees raised $150,000 to help fund cancer research.



2004 Progress Energy Foundation Grants

We're investing in our future, from every angle.

Our support of sea turtle rehabilitation and release programs is just one part of our commitment to a healthy environment. *(Dave Bruzek and Cindy Armstrong, Progress Energy environmental specialists, with "Arnold.")*

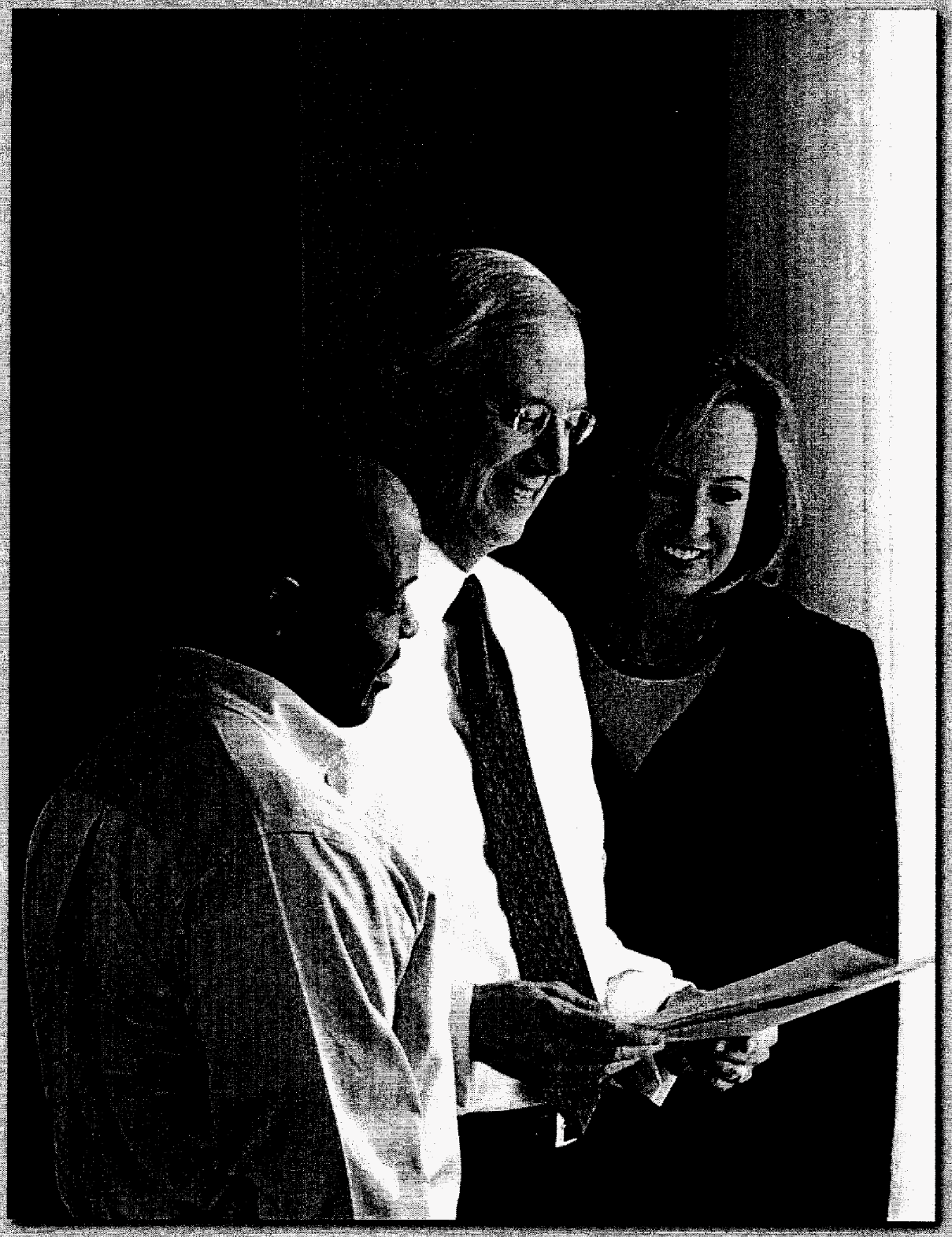
Pursuing new ways to cultivate our future. As a company that serves communities, we're only as strong as they are. That's why we consider investments that improve the quality of life in our cities and towns so valuable. Whether it's supporting clean air or good teachers, creative partnerships or involved employees, we're investing in initiatives that will produce real returns, not just for communities, but for shareholders, too.

Progress Energy is committed to putting our environmental policy into practice every day. In connection with the Clean Smokestacks Act of 2002, we're spending approximately $895 million on technologies that reduce emissions from our coal-fired generating plants in North Carolina, helping our plants run even cleaner and protecting the air around them.

In 2004, we forged a long-term agreement with a manufacturer of wall and ceiling products to provide high-quality synthetic gypsum for use in wallboard production. Synthetic gypsum is a byproduct of scrubbers, one of the technologies we're using to reduce emissions at our plants. It's not only an innovative way to protect our environment – the agreement will create approximately 200 jobs.

We expanded our Progress Energy Leadership Institute Program into Florida this year, with a grant of $1 million to the University of Central Florida. Since 2001, 717 superintendents and principals in the Carolinas and Florida have completed the program, which teaches the application of best business practices to the academic world.

At Progress Energy, making thoughtful social and environmental investments will remain an important part of our business in the coming years, not only because of the responsibility we have to our customers, but because of the one we have to our investors.



Lloyd Yates – senior vice president, Energy Delivery, Progress Energy Carolinas
Robert B. McGehee – chairman and chief executive officer
Sarah Rogers – vice president, Transmission

Our vision for Progress Energy in 2005 is simple.

We'll focus on our proven strengths to deliver

proven value. And we'll settle for nothing less

than excellence.

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.
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
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); 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.

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 Service Company, LLC, and Chairman, Progress Energy Ventures, Inc.

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); Audit and Corporate Performance; Finance.

Richard A. Nunis
President, New Business Solutions, Inc., and Retired Chairman, Walt Disney Parks and Resorts
Orlando, Fla.

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

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.

Jean Giles Wittner
President and Secretary, Wittner & Co., Inc., and subsidiaries (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.

The Sarbanes-Oxley Act of 2002 requires the inclusion of a report regarding internal controls over financial reporting in annual reports. As a result of our focus on this issue throughout 2004, Progress Energy has achieved full compliance with the applicable requirements.

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
President and Chief Executive Officer
Progress Energy Service Company, LLC

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

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

Geoffrey S. Chatas
Executive Vice President and
Chief Financial Officer

Donald K. Davis
Executive Vice President – Diversified Operations

Mourant
Senior Vice President – Nuclear Generation

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

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

Michael Williams
Senior Vice President – Power Operations

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

FINANCIAL REPORT

Management's Discussion and Analysis 20
Market Risk Disclosures 48
Forward-Looking Statements 51
Independent Auditors' and Management Reports 52
Consolidated Financial Statements
- Income 55
- Balance Sheets 56
- Cash Flows 58
- Changes in Common Stock Equity 59
- Comprehensive Income 59

Notes to Consolidated Financial Statements 60
Selected Consolidated Financial and Operating Data (Unaudited) 110
Reconciliation of Ongoing Earnings Per Share to Reported GAAP Earnings Per Share (Unaudited) 111

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. Management's Discussion and Analysis should be read in conjunction with the Progress Energy Consolidated Financial Statements.

INTRODUCTION

The Company's reportable business segments and their primary operations include:

- Progress Energy Carolinas Electric (PEC Electric) – 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 portions of Florida;
- Competitive Commercial Operations (CCO) – engaged in nonregulated electric generation operations and marketing activities primarily in the southeastern United States;
- Fuels – primarily engaged in natural gas production in Texas and Louisiana, coal mining and related services, and the production of synthetic fuels and related services, which are located in Kentucky, West Virginia and Virginia; and
- Rail Services (Rail) – engaged in various rail and railcar-related services in 23 states, Mexico and Canada.

The Progress Ventures business unit consists of the Fuels and CCO operating segments. The Corporate and Other category includes other businesses engaged in other nonregulated business areas, including telecommunications, primarily in the eastern United States, and energy services operations and holding company results, which do not meet the requirements for separate segment reporting disclosure.

In 2004, the Company realigned its business segments to no longer report the other nonregulated businesses as a reportable business segment. For comparative purposes, 2003 and 2002 segment information has been restated to align with the 2004 reporting structure.

Strategy

Progress Energy is an integrated energy company, with its primary focus on the end-use and wholesale electricity markets. The Company operates in retail utility markets in the southeastern United States and competitive markets in the eastern United States. The target is to develop a business mix of approximately 80% regulated and 20% nonregulated business. The Company is focused on achieving the following key goals: restoring balance sheet strength and flexibility, disciplined capital and operations and maintenance (O&M) management to support earnings and current dividend policy and achieving constructive regulatory frameworks in all three regulated jurisdictions. A summary of the significant financial objectives or issues impacting Progress Energy, its regulated utilities and nonregulated operations is addressed more fully in the following discussion.

Progress Energy has several key financial objectives, the first of which is to achieve sustainable earnings growth in its three core energy businesses, which include PEC Electric, PEF and Progress Ventures (excluding synthetic fuels). In addition, the Company seeks to continue its track record of dividend growth, as the Company has increased its dividend for 17 consecutive years, and 29 of the last 30. The Company also seeks to restore balance sheet strength and flexibility by reducing its debt to total capitalization ratio through selected asset sales, free cash flow (defined as cash from operations less capital expenditures and common dividends) and increased equity from retained earnings and ongoing equity issuances.

In the short term the Company's ability to achieve its objectives will be impacted by, among other things, its ability to recover storm costs incurred during 2004, cash flow available to reduce debt after funding capital expenditures and common dividends, obtaining a reasonable rate agreement in Florida at the expiration of the current agreement in December 2005 and the outcome of the ongoing Internal Revenue Service (IRS) audit of the Company's synthetic fuel facilities. The Company's long-term challenges include escalating nonfuel operating costs, the need for sufficient earnings growth to sustain the track record of dividend growth, and the scheduled expiration of the Section 29 tax credit program for its synthetic fuels business at the end of 2007.

The Company's ability to meet its financial objectives is largely dependent on the earnings and cash flows of its two regulated utilities. The regulated utilities contributed $797 million of net income and produced 100% of consolidated cash flow from operations in 2004. In

addition, Fuels contributed $180 million of net income, of which $91 million represented synthetic fuel net income. Partially offsetting the net income contribution provided by the regulated utilities and Fuels was a loss of $236 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

While the Company's synthetic fuel operations currently provide significant earnings that are scheduled to expire at the end of 2007, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred tax credits are ultimately utilized. Credits that have been generated but not yet utilized are carried forward indefinitely as alternative minimum tax credits and will provide positive cash flow when utilized. At December 31, 2004, deferred credits were $745 million. See Note 23E for additional information on the Company's synthetic fuel operations and its ability to utilize its current and future tax credits.

Progress Energy reduced its debt to total capitalization ratio to 57.6% at the end of 2004 as compared to 58.8% at the end of 2003. The Company seeks to continue to improve this ratio as it plans to reduce total debt with proceeds from asset sales, free cash flow (defined as cash from operations less capital expenditures and common dividends) and growth in equity from retained earnings and ongoing equity issuances. The Company expects total capital expenditures to be approximately $1.3 billion in both 2005 and 2006.

Progress Energy's ratings outlook was changed to "negative" from "stable" in 2004 by both Moody's and Standard & Poor's (S&P). Both these ratings agencies cited the uncertainty around the timing of storm cost recovery, potential delays in the Company's de-leveraging plan, uncertainty about the upcoming rate case in Florida and uncertainty about the IRS audit of the Company's synthetic fuel partnerships in their ratings actions. The change in outlook has not materially affected Progress Energy's access to liquidity or the cost of its short-term borrowings. If Standard & Poor's lowers Progress Energy's senior unsecured rating one ratings category to BB+ from its current rating, it would be a non-investment grade rating. The effect of a noninvestment grade rating would primarily be to increase borrowing costs. The Company's liquidity would essentially remain unchanged as the Company believes it could borrow under its revolving credit facilities instead of issuing commercial paper for its short-term borrowing needs. However, there would be additional funding requirements of approximately $450 million due to ratings triggers embedded in various contracts. See "Guarantees" Section under FUTURE LIQUIDITY AND CAPITAL RESOURCES below for more information regarding the potential impact on the Company's financial condition and results of operations resulting from a ratings downgrade.

REGULATED UTILITIES

The regulated utilities earnings and operating cash flows are heavily influenced by weather, including related storm damage, the economy, demand for electricity related to customer growth, actions of regulatory agencies and cost controls.

Both PEC Electric and PEF operate in retail service territories that are forecasted to have income and population growth higher than the U.S. average. In recent years, lower industrial sales mainly related to weakness in the textile sector at PEC Electric have negatively impacted earnings growth. The Company does not expect any significant improvement in industrial sales in the near term. These combined factors under normal weather conditions are expected to contribute approximately 2% annual retail kilowatt-hour (KWh) sales growth at PEC Electric and approximately 3% annual retail kilowatt-hour (KWh) sales growth at PEF through at least 2007. The utilities must continue to invest significant capital in 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 financial growth in the utilities. The Company will meet this load growth through the two previously planned approximately 500 MW combined-cycle units at PEF's Hines Energy Complex in 2005 and 2007. The contribution from the utilities' regulated wholesale business is expected to increase slightly in 2005 and be relatively flat over the following few years.

While the two utilities expect retail sales growth in the future, they are facing rising costs. The Company began a cost-management initiative in late 2004 to permanently reduce by $75 million to $100 million the projected growth in the Company's annual nonfuel O&M costs by the end of 2007. See "Cost-Management Initiative" under RESULTS OF OPERATIONS for more information. The utilities expect capital expenditures to be approximately $1.1 billion in both 2005 and 2006. The Company will continue an approximate $900 million program of installing new emission-control equipment at PEC's coal-fired power plants in North Carolina. Operating cash flows are expected to be sufficient to fund capital spending in 2005 and in 2006.

The costs associated with the unprecedented series of major hurricanes that impacted the Company's service territories significantly impacted the utility operations in 2004. Restoration of the Company's systems from hurricane-related damage cost almost $400 million. Although PEF has filed for recovery of approximately $252 million of these storm costs, the timing of recovery is not certain at this time. See OTHER MATTERS below for more information on storm costs incurred during 2004.

PEC Electric and PEF continue to monitor progress toward a more competitive environment. No retail electric restructuring legislation has been introduced in the jurisdictions in which PEC Electric and PEF operate. As part of the Clean Smokestacks bill in North Carolina and an agreement with the Public Service Commission of South Carolina (SCPSC), PEC Electric is operating under a rate freeze in North Carolina through 2007 and an agreement not to seek a base retail electric rate increase in South Carolina through 2005. PEF is operating under a retail rate agreement in Florida through 2005. PEF has initiated a rate proceeding in 2005 regarding its future base rates. See Note 8 for further discussion of the utilities' retail rates.

NONREGULATED BUSINESSES

The Company's primary nonregulated businesses are CCO, Fuels and Progress Rail.

Cash flows and earnings of the nonregulated businesses are impacted largely by the ability to obtain additional term contracts or sell energy on the spot market at favorable terms, the volume of synthetic fuel produced and tax credits utilized, and volumes and prices of both coal and natural gas sales.

Progress Energy expects an excess of supply in the wholesale electric energy market for the next several years. During 2004, CCO entered into additional wholesale power contracts with cooperatives in Georgia and will serve approximately one-third of the Georgia cooperative market starting in 2005. CCO completed the build out of its nonregulated generation assets in 2003 and currently has total capacity of 3,100 MW. The Company has no current plans to expand its portfolio of nonregulated generating plants. CCO short-term challenges include absorbing the fixed costs associated with these plants and the general weakness in wholesale power markets. Three above-market tolling agreements for approximately 1,200 MW of capacity expired at the end of 2004. CCO has replaced the expired agreements with the increased cooperative load in Georgia. The increased cooperative load in Georgia will significantly increase CCO's revenue and cost of sales from 2004 to 2005 with lower margins expected. Currently CCO has contracts for its planned production capacity, which includes callable resources from the cooperatives, of approximately 77% for 2005, 81% for 2006 and 75% for 2007. CCO will continue its optimization strategy for the nonregulated generation portfolio.

Fuels will continue to develop its natural gas production asset base both as a long-term economic hedge for the Company's nonregulated generation fuel needs and to continue its presence in natural gas markets that will allow it to provide attractive returns for the Company's shareholders.

The Company has begun exploring strategic alternatives regarding the Fuels' coal mining business, which could include divesting assets. As of December 31, 2004, the carrying value of long-lived assets of the coal mining business was $66 million.

The Company, through its subsidiaries, is a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied. These facilities have private letter rulings (PLRs) from the IRS with respect to their synthetic fuel operations. However, these PLRs do not address placed-in-service date requirements. The Company has resolved certain synthetic fuel tax credit issues with the IRS and is continuing to work with the IRS to resolve any remaining issues. The Company cannot predict the final resolution of any outstanding matters. The Company has no current plans to alter its synthetic fuel production schedule as a result of these matters. The Company plans to produce approximately 8 million to 12 million tons of synthetic fuel in 2005. Through December 31, 2004, the Company had generated approximately $1.5 billion of synthetic fuel tax credits to date (including FPC prior to the acquisition by the Company). See additional discussion of synthetic fuel tax credits in Note 23E.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 24 for more information.

Progress Energy and its consolidated subsidiaries are subject to various risks. For a complete discussion of these risks, see the Company's filings with the SEC.

RESULTS OF OPERATIONS

For 2004 as compared to 2003 and 2003 as compared to 2002

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

Overview

For the year ended December 31, 2004, Progress Energy's 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 due to the impact of hurricanes during the year.
- Lower off-system wholesale sales, primarily at PEC Electric.
- Higher O&M expenses at PEC Electric.
- Recording of litigation settlement reached in the civil suit by Strategic Resource Solutions (SRS).
- Decreased nonregulated generation earnings due to receipt of a contract termination payment on a tolling agreement in 2003, loss recognized on early extinguishment of debt in 2004 and higher fixed costs and interest charges in 2004.
- Reduction in revenues due to customer outages in Florida 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 in Florida.
- Favorable customer growth in both the Carolinas and Florida.
- Increased margins as a result of the allowed return on the Hines Unit 2 in Florida.
- Increased earnings for natural gas operations, which include the gain recorded on the disposition of certain Winchester Production Company assets.
- Increased earnings for Rail 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 discontinued operations.
- Reduction in losses recorded for changes in accounting principles.

For the year ended December 31, 2003, Progress Energy's net income was $782 million, or $3.30 per share, compared to $528 million, or $2.43 per share, for the same period in 2002. Income from continuing operations before the cumulative effect of changes in accounting principles and discontinued operations was $811 million in 2003, a 47% increase from $552 million in 2002. Net income for 2003 increased compared to 2002 primarily due to the inclusion in 2002 of an impairment of $265 million after-tax related to assets in the telecommunications and rail businesses. The Company recorded impairments of $23 million after-tax in 2003 on an investment portfolio and on long-lived assets. The increase in net income in 2003 of $12 million, excluding the impairments, is primarily due to:

- Increase in retail customer growth at the utilities.
- Growth in natural gas production and sales.
- Higher synthetic fuel sales.
- Absence of severe storm costs incurred in 2002 in the Carolinas.
- Lower loss recorded in 2003 related to the sale of North Carolina Natural Gas Company (NCNG), with the majority of the loss on the sale being recorded in 2002.
- Lower interest charges in 2003.

Partially offsetting these items were the:

- Net impact of the 2002 Florida Rate settlement.
- Impact of the change in the fair value of the CVOs.
- Milder weather in 2003 as compared to 2002.
- Increased benefit-related costs.
- Higher depreciation expense at both utilities and the Fuels and CCO segments.
- The impact of changes in accounting principles in 2003.

Basic earnings per share decreased in 2004 and increased in 2003 due in part to the factors outlined above. Dilution related to issuances under the Company's Investor Plus and employee benefit programs in 2004 also reduced basic earnings per share by $0.06 in 2004. Dilution related to a November 2002 equity issuance of 14.7 million shares and issuances under the Company's Investor Plus and employee benefit programs in 2002 and 2003 also reduced basic earnings per share by $0.33 in 2003.

Beginning in the fourth quarter of 2003, the Company ceased recording portions of the Fuels segment's

operations, primarily synthetic fuel facilities, one month in arrears. As a result, earnings for the year ended December 31, 2003, included 13 months of operations, resulting in a net income increase of $2 million for the year.

The Company's segments contributed the following profit or loss from continuing operations:

(in millions)	**2004**	Change	2003	Change	2002
PEC Electric	**$464**	$(51)	$515	$2	$513
PEF	**333**	38	**295**	(28)	**323**
Fuels	**180**	(55)	**235**	59	**176**
CCO	**(4)**	(24)	**20**	(7)	**27**
Rail services	**16**	17	(1)	41	(42)
Total segment profit (loss)	**989**	(75)	1,064	67	997
Corporate and other	**(236)**	17	(253)	192	(445)
Total income from continuing operations	**753**	(58)	811	259	552
Discontinued operations, net of tax	**6**	14	(8)	16	(24)
Cumulative effect of changes in accounting principles	**–**	21	(21)	(21)	–
Net income	**$759**	$(23)	$782	$254	$528

In March 2003, the SEC completed an audit of Progress Energy Service Company, LLC (Service Company), and recommended that the Company change its cost allocation methodology for allocating Service Company costs. As part of the audit process, the Company was required to change the cost allocation methodology for 2003 and record retroactive reallocations between its affiliates in the first quarter of 2003 for allocations originally made in 2001 and 2002. This change in allocation methodology and the related retroactive adjustments have no impact on consolidated expense or earnings. The new allocation methodology, as compared to the previous allocation methodology, generally decreases expenses in the regulated utilities and increases expenses in the nonregulated businesses. The regulated utilities' reallocations are within O&M expense, while the diversified businesses' reallocations are generally within diversified business expenses. The impact on the individual lines of business is included in the following discussions.

Cost-Management Initiative

On February 28, 2005, as part of a previously announced cost-management initiative, the executive officers of the Company approved a workforce restructuring. The restructuring will result in a reduction of approximately 450 positions and is expected to be completed in September of 2005. The cost-management initiative is designed to permanently reduce by $75 million to $100 million the projected growth in the Company's annual operation and maintenance expenses by the end of 2007. In addition to the workforce restructuring, the cost-management initiative includes a voluntary enhanced retirement program.

In connection with the cost-management initiative, the Company expects to incur one-time pre-tax charges of approximately $130 million. Approximately $30 million of that amount relates to payments for severance benefits, and will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $100 million will be recognized in the second quarter of 2005 and relates primarily to postretirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program. Approximately 3,500 of the Company's 15,700 employees are eligible to participate in the voluntary enhanced retirement program. The total cost-management initiative charges could change significantly depending upon how many eligible employees elect early retirement under the voluntary enhanced retirement program and the salary, service years and age of such employees (See Note 24).

Energy Delivery Capitalization Practice

The Company has reviewed its capitalization policies for its Energy Delivery business units in PEC and PEF. 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. The Company has implemented such changes effective January 1, 2005, which include more detailed classification of outage and emergency work and result in more precise estimation and a process of retesting 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 Company estimates that the combined impact for both utilities in 2005 will be that approximately $55 million of costs that would have been capitalized under the previous policies will be expensed. Pursuant to SFAS No. 71, PEC and PEF have informed the state regulators having jurisdiction over them of this change and that the new estimation process will be implemented effective January 1, 2005. The Company has also requested a method change from the IRS.

Progress Energy Carolinas Electric

PEC Electric contributed segment profits of $464 million, $515 million and $513 million in 2004, 2003 and 2002, respectively. The decrease in profits for 2004 as compared to 2003 is 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. The slight increase in profits in 2003, when compared to 2002, was primarily due to customer growth, strong wholesale sales during the first quarter of 2003, lower Service Company allocations and lower interest costs, which were offset by unfavorable weather in 2003, higher depreciation expense and increased benefit-related costs.

REVENUES

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

(in millions)					
Customer Class	**2004**	% Change	2003	% Change	2002
Residential	**$1,324**	5.2	$1,259	1.5	$1,241
Commercial	**888**	4.5	850	2.2	832
Industrial	**659**	3.6	636	(1.4)	645
Governmental	**82**	3.8	79	1.3	78
Total retail revenues	**2,953**	4.6	2,824	1.0	2,796
Wholesale	**575**	(16.3)	687	5.5	651
Unbilled	**10**	–	(6)	–	15
Miscellaneous	**90**	7.1	84	9.1	77
Total electric revenues	**$3,628**	1.1	$3,589	1.4	**$3,539**

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

(in thousands of MWh)					
Customer Class	**2004**	% Change	2003	% Change	2002
Residential	**16,003**	4.7	15,283	0.3	15,239
Commercial	**13,019**	3.7	12,557	0.7	12,468
Industrial	**13,036**	2.3	12,749	(2.6)	13,089
Governmental	**1,431**	1.6	1,408	(2.0)	1,437
Total retail energy sales	**43,489**	3.6	41,997	(0.6)	42,233
Wholesale	**13,222**	(14.8)	15,518	3.3	15,024
Unbilled	**91**	–	(44)	–	270
Total MWh sales	**56,802**	1.2	57,471	(0.1)	57,527

PEC Electric's revenues, excluding recoverable fuel revenues of $933 million and $901 million for 2004 and 2003, respectively, increased $7 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% above prior year. Retail customer growth contributed an additional $55 million in revenues in 2004. PEC Electric's retail customer base increased as approximately 26,000 new customers were added in 2004. The increase in retail revenues was offset partially by lower wholesale revenues. Wholesale revenues decreased $86 million when compared to $393 million in 2003. The decrease in PEC Electric'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 is attributable to an inelastic power market. While the cost of fuel continues to rise, the power market prices have not responded as quickly to the fuel increases. The differential between fuel cost and market price limited opportunities to enter the market. PEC monitors its wholesale contract portfolio on a regular basis. During 2003 and 2004, several contracts expired or were renegotiated at lower prices. Due to the slightly depressed wholesale market and increased competition, this trend could continue as contracts are renewed in the upcoming years. The expiration and renegotiation of wholesale contracts is a normal business activity. PEC actively manages its portfolio by seeking to sign new contracts to replace expiring arrangements.

PEC Electric's revenues, excluding recoverable fuel revenues of $901 million and $851 million in 2003 and 2002, respectively, were unchanged from 2002 to 2003. Milder weather in 2003, when compared to 2002, accounted for a $61 million retail revenue reduction. While heating degree days in 2003 were 4.8% above prior year, cooling degree days were 25.2% below prior year. However, the more severe weather in the northeast region of the United States during the first quarter of 2003 drove a $19 million increase in wholesale revenues. Additionally, retail customer growth in 2003 generated an additional $42 million of revenues in 2003. PEC Electric's retail customer base increased as approximately 23,000 new customers were added in 2003.

Downturns in the economy during 2002 and 2003 impacted energy usage within the industrial customer class. Total industrial revenues, excluding fuel revenues, declined during 2003 when compared to 2002 by $13 million, as sales to industrial customers decreased due to a general industrial slowdown. Decreases in the textile industry and the chemical industry were among the largest. This

declining trend leveled out in 2004 as industrial sales increased in the primary and fabricated metal, chemicals, lumber and food industries. Industrial sales growth is expected to be flat or very low as expired textile quotas are expected to lower textile sales and balance gains in other 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 $1.137 billion for 2004, which represents a $16 million increase compared to the same period in the prior year. Fuel used in electric generation increased $11 million to $836 million compared to the prior year. This increase is due to an increase in fuel used in generation of $78 million due to higher fuel costs and a change in generation mix. Higher fuel costs are being driven primarily by an increase in coal prices. Outages at several nuclear 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 underrecovery of current period fuel costs. 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.

Fuel and purchased power expenses were $1.121 billion for 2003, which represents a $22 million increase compared to the same period in the prior year. Fuel used in electric generation increased $73 million in 2003, compared to prior year, primarily due to higher prices incurred for coal, oil and natural gas used during generation. Costs for fuel per Btu increased for all three commodities during the year. Purchased power expense decreased $51 million in 2003, compared to $347 million in 2002, mainly due to a decrease in the volume purchased as milder weather reduced system requirements and due to the renegotiation at more favorable terms of two contracts that expired during the year.

Operations and Maintenance (O&M)

O&M expenses were $871 million for 2004, which represents an $89 million increase compared to 2003. This increase is driven primarily by higher outage costs and storm costs in 2004 than in the prior year. 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 $18 million. Storm costs for 2004 included costs related to an ice storm and Hurricanes Charley and Ivan in the North Carolina service territory. PEC Electric also incurred storm costs in 2003; however, the Company requested and the NCUC approved deferral of these costs. The Company did not seek to defer costs associated with the ice storm, which hit the North Carolina service territory, and Hurricanes Charley and Ivan. O&M expenses also increased $9 million due to higher salary- and benefit-related expenditures. In addition, O&M charges in the prior year were favorably impacted by $16 million related to the retroactive reallocation of Service Company costs.

O&M expenses were $782 million in 2003, which represents a $20 million decrease compared to 2002. O&M expense in 2002 included severe storm costs of $27 million. Those costs, along with lower 2003 Service Company allocations of $16 million, due to the change in allocation methodology as required by the SEC in early 2003, are the primary reasons for decreased O&M expenses. This decrease was partially offset by higher benefit-related costs of $21 million. PEC Electric incurred O&M costs of $25 million related to three severe storms in 2003. The NCUC allowed deferral of $24 million of these storm costs. These costs are being amortized over a five-year period, beginning in the months the expenses were incurred. PEC Electric amortized $3 million of these costs in 2003, which is included in depreciation and amortization expense on the Consolidated Income Statement.

Depreciation and Amortization

Depreciation and amortization expense was $570 million for 2004, which represents an $8 million increase compared to 2003. This increase is attributable primarily to the impact of the NC Clean Air legislation. PEC Electric recorded the maximum amortization allowed under the legislation in 2004. NC Clean Air amortization increased $100 million to $174 million in 2004 compared to $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 the year.

During 2004, PEC met the requirements of both the NCUC and the SCPSC for the implementation of 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 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.

Depreciation and amortization increased $38 million in 2003, compared to $524 million in 2002. Depreciation and amortization increased $74 million related to the 2003 impact of the NC Clean Air legislation and decreased $53 million related to the 2002 impact of the accelerated nuclear amortization program. Both programs are approved by the state regulatory agencies and are discussed further at Notes 8B and 22. In addition, depreciation increased $19 million due to additional assets placed into service.

Taxes Other than on Income

Taxes other than on income were $173 million for 2004, which represents an $11 million increase compared to the prior year. 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.

Taxes other than on income were $162 million in 2003, which represents a $4 million increase compared to prior year. This increase is due to an increase in property taxes and payroll taxes of $2 million each.

Interest Expense

Net interest expense was $192 million, $197 million and $212 million in 2004, 2003 and 2002, respectively. Declines in interest expense in 2003 resulted from reduced short-term debt and refinancing certain long-term debt with lower interest rate debt.

Income Tax Expense

Income tax expense was $237 million, $238 million and $237 million in 2004, 2003 and 2002, respectively. In 2004, 2003 and 2002, $22 million, $24 million and $35 million, respectively, of the tax benefit that was previously held at the Company's holding company was allocated to PEC Electric. As required by an SEC order issued in 2002, certain holding company tax benefits are allocated to profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Progress Energy Florida

PEF contributed segment profits of $333 million, $295 million and $323 million in 2004, 2003 and 2002, respectively. 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. The decrease in profits in 2003, when compared to 2002, was primarily due to the impact of the 2002 rate case stipulation, higher benefit-related costs primarily related to higher pension expense, higher depreciation and the unfavorable impact of weather. These amounts were partially offset by continued customer growth and lower interest charges.

In 2002, PEF's profits were affected by the outcome of the rate case stipulation, which included a one-time retroactive revenue refund, a decrease in retail rates of 9.25% (effective May 1, 2002), provisions for revenue sharing with the retail customer base, lower depreciation and amortization and increased service revenue rates (See Note 8C).

REVENUES

PEF's electric revenues and the percentage change by year and by customer class, as well as the impact of the rate case settlement on revenue, are as follows:

(in millions)

Customer Class	2004	% Change	2003	% Change	2002
Residential	**$1,806**	6.8	$1,691	2.8	$1,645
Commercial	**853**	15.3	740	1.2	731
Industrial	**254**	16.0	219	3.8	211
Governmental	**211**	16.6	181	4.6	173
Revenue sharing refund	**(11)**		(35)		(5)
Retroactive retail rate refund	**–**	–	–	–	(35)
Total retail revenues	**3,113**	11.3	2,796	2.8	2,720
Wholesale	**268**	18.1	227	(1.3)	230
Unbilled	**7**	–	(2)	–	(3)
Miscellaneous	**137**	4.6	131	13.9	115
Total electric revenues	**$3,525**	11.8	$3,152	2.9	$3,062

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

(in thousands of MWh)					
Customer Class	**2004**	% Change	2003	% Change	2002
Residential	**19,347**	(0.4)	19,429	3.6	18,754
Commercial	**11,734**	1.6	11,553	1.2	11,420
Industrial	**4,069**	1.7	4,000	4.3	3,835
Governmental	**3,044**	2.4	2,974	4.4	2,850
Total retail energy sales	**38,194**	**0.6**	**37,956**	**3.0**	**36,859**
Wholesale	**5,101**	18.0	4,323	3.4	4,180
Unbilled	**358**	–	233	–	5
Total MWh sales	**43,653**	2.6	42,512	3.6	41,044

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 has 37,000 additional retail customers compared to prior year. Revenues were also favorably impacted by a reduction in the provision for revenue sharing of $24 million. 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 increased revenues by $11 million. 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 8C). These increases were partially offset by the reduction in revenues related to customer outages for Hurricanes Charley, Frances and Jeanne of approximately $12 million and the impact of milder weather in the current year of $10 million.

PEF's revenues, excluding recoverable fuel and other pass-through revenues of $1.692 billion and $1.602 billion in 2003 and 2002, respectively, were unchanged from 2002 to 2003. Revenues were favorably impacted by $49 million in 2003, primarily as a result of customer growth (approximately 36,000 additional customers). In addition, other operating revenues were favorable by $16 million due primarily to higher wheeling and transmission revenues and higher service charge revenues (resulting from increased rates allowed under the 2002 rate settlement). These increases were offset by the negative impact of the rate settlement, which decreased revenues, lower wholesale sales and the impact of unfavorable weather. The provision for revenue sharing increased $12 million in 2003 compared to the $5 million provision recorded in 2002. Revenues in 2003 were also impacted by the final resolution of the 2002 revenue sharing provisions, as the FPSC issued an order in July 2003 that required PEF to refund an additional $18 million to customers related to 2002. The 9.25% rate reduction from the settlement accounted for an additional $46 million decline in revenues. The 2003 impact of the rate settlement was partially offset by the absence of the prior year interim rate refund of $35 million. Lower wholesale revenues (excluding fuel **revenues) of $17 million and the $8 million impact** of milder weather also reduced base revenues during 2003.

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 $1.742 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 underrecovered fuel expenses. In November 2003, the FPSC approved PEF's request for a cost adjustment in its annual fuel filing due to the rising costs of fuel. The new rates became effective January 2004.

Fuel used in generation and purchased power expenses were $1.436 billion in 2003, which represents an $87 million increase compared to the prior year. Higher costs to generate electricity and higher purchased power costs as a result of an increase in volume due to system requirements and higher natural gas prices resulted in a $229 million increase partially offset by the deferral of 2003 underrecovered fuel and purchased power expense of $142 million.

Operations and Maintenance (O&M)

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.

O&M expenses were $640 million in 2003, which represents a $49 million increase when compared to the prior year. The increase is largely related to increases in certain benefit-related expenses of $36 million, which consisted primarily of higher pension expense of $27 million and higher operational costs related to the Crystal River Unit 3 nuclear outage and plant maintenance.

Depreciation and Amortization

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 that was 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 2 in the revenues analysis above.

Depreciation and amortization was $307 million in 2003, which represents an increase of $12 million when compared to 2002. Depreciation increased primarily as a result of additional assets being placed into service that were partially offset by lower amortization of the Tiger Bay regulatory asset of $2 million, which was fully amortized in September 2003.

Taxes Other than on Income

Taxes other than on income were $254 million in 2004, which represents an increase of $13 million compared to the prior year. 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.

Taxes other than on income were $241 million in 2003, which represents an increase of $13 million compared to prior year. This increase was due to increases in payroll taxes of $10 million and increases in gross receipts and franchise taxes of $4 million combined.

Interest Expense

Interest charges, net were $114 million in 2004, which represents an increase of $23 million compared to the prior year. Interest charges, net were $91 million in 2003, which represents a $15 million decrease compared to the prior year. The fluctuations were 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 $174 million, $147 million and $163 million in 2004, 2003 and 2002, respectively. In 2004, 2003 and 2002, $14 million, $13 million and $20 million, respectively, of the tax benefit that was previously held at the Company's holding company was allocated to PEF. As required by an SEC order issued in 2002, certain holding company tax benefits are allocated to profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Diversified Businesses

The Company's diversified businesses consist of the Fuels segment, the CCO segment and the Rail Services segment.

Fuels

The Fuels' segment operations include synthetic fuel production, natural gas production, coal extraction and terminal operations. Beginning in the fourth quarter of 2003, the Company ceased recording portions of Fuels' segment operations, primarily synthetic fuel facilities, one month in arrears. As a result, earnings for the year ended December 31, 2003, included 13 months of operations, resulting in a net income increase of $2 million for the year.

The following summarizes Fuels' segment profits:

(in millions)	**2004**	2003	2002
Synthetic fuel operations	**$91**	$205	$156
Natural gas operations	**85**	34	10
Coal fuel and other operations	**4**	(4)	10
Segment profits	**$180**	$235	$176

SYNTHETIC FUEL OPERATIONS

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

The operations resulted in the following losses (prior to tax credits):

(in millions)	**2004**	2003	2002
Tons sold	**8.3**	12.4	11.2
After-tax losses (excluding tax credits)	**$(124)**	$(141)	$(135)
Tax credits	**215**	346	291
Net profit	**$91**	$205	$156

The Company's synthetic fuel production levels and the amount of tax credits it can claim each year are a function of the Company's projected consolidated regular federal income tax liability. 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. The Company's total synthetic fuel production of approximately eight million tons in 2004 is down compared to 2003 production levels of approximately 12 million tons as a result of hurricane costs, which reduced the Company's projected 2004 regular tax liability and its corresponding ability to record tax credits from its synthetic fuel production. In addition, earnings in 2003 include a $13 million favorable tax credit true-up related to 2002.

As of September 30, 2004, the Company anticipated an ability to record approximately five million tons of synthetic fuel production based on the Company's projected regular tax liability for 2004. This estimate was based upon the Company's projected casualty loss as a result of the storms. Therefore, the Company recorded a charge of $79 million in the third quarter for tax credits associated with approximately 2.7 million tons sold during the year that the Company anticipated it would not be able to use. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from customers over a two-year period. Based on a reasonable expectation at December 31, 2004, that the FPSC will grant the requested recovery of the storm costs, the Company's loss from the casualty is less than originally anticipated. Accordingly, as of December 31, 2004, the Company's anticipated 2004 tax liability supported credits on approximately eight million tons. Therefore, the Company recorded tax credits of $90 million for the quarter ended December 31, 2004, for tax credits associated with approximately three million tons sold during the year that the Company now anticipates can be used. As of December 31, 2004, the Company anticipates that approximately $7 million of tax credits associated with approximately 0.2 million tons sold during the year could not be used (See Note 23E). The Company ceased operations at its Earthco facilities for the last three months of 2004 due to the decrease in the Company's projected 2004 tax liability, and these facilities were restarted in January 2005.

The Company believes its right to recover storm costs is well established; however, the Company cannot predict the timing or outcome of this matter. If the FPSC should deny PEF's petition for the recovery of storm costs in 2005, there could be a material impact on the amount of 2005 synthetic fuel production and results of operations.

Synthetic fuels' net profits for 2003 increased as compared to 2002 due to higher sales, improved margins and a higher tax credit per ton. The 2003 tax credits also include a $13 million favorable true-up from 2002. Additionally, synthetic fuels' results in 2003 include 13 months of operations for some facilities. Prior to the fourth quarter of 2003, results of these synthetic fuels' operations had been recognized one month in arrears. The net impact of this action increased net income by $2 million for the year.

NATURAL GAS OPERATIONS

Natural gas operations generated profits of $85 million, $34 million and $10 million for the years ended December 31, 2004, 2003 and 2002, respectively. Natural gas profits increased $51 million in 2004 compared to 2003. This increase is attributable primarily to the gain recognized on the sale of gas assets during the year. In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd. (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 the Company's remaining oil and gas properties. 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. Volume and prices have increased 21% and 16%, respectively, for 2004 compared to 2003.

Natural gas profits increased to $34 million in 2003 compared to $10 million in 2002. The increase in production and price resulting from the acquisitions of Westchester in 2002 (renamed Winchester Energy in 2004) and North Texas Gas in the first quarter of 2003 drove increased revenue and earnings in 2003 compared to 2002. In October 2003, the Company completed the sale of certain gas-producing properties owned by Mesa Hydrocarbons, LLC (Mesa). See Notes 5B and 4D to the Progress Energy Consolidated Financial Statements for discussions of the North Texas Gas acquisitions and the Mesa disposition.

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

	2004	2003	2002
Production in Bcf equivalent			
East Texas/LA gas operations	**20**	13	6
North Texas gas operations	**10**	7	
Mesa	–	5	7
Total production	**30**	25	13
Revenues in millions			
East Texas/LA gas operations	**$110**	$65	$24
North Texas gas operations	**52**	38	–
Mesa	–	13	15
Total revenues	**$162**	$116	$39
Gross margin			
In millions of $	**$126**	$91	$29
As a % of revenues	**78%**	78%	74%

COAL FUEL AND OTHER OPERATIONS

Coal fuel and other operations generated profits of $4 million, losses of $4 million and profits of $10 million for the years ended December 31, 2004, 2003 and 2002, respectively. The increase in profits for 2004 is primarily due to higher volumes and margins for coal fuel operations of $16 million after-tax. In addition, coal results in 2003 included the recording of an impairment of certain assets at the Kentucky May coal mine totaling $11 million after-tax. This favorability was offset by a reduction in profits of $7 million after-tax for fuel transportation operations related to the waterborne transportation ruling by the FPSC (See Note 8C). Profits were also negatively impacted by higher corporate costs of $10 million in 2004. Corporate costs in the prior year included $4 million of favorability related to the reduction of an environmental reserve (See Note 22). The remaining unfavorability in corporate costs is attributable to increased interest expense related to unresolved tax matters and higher professional fees.

Coal fuel and other operations' profits decreased $9 million from 2002 to 2003. The decrease is due primarily to the recording of an impairment of certain assets at the Kentucky May coal mine totaling $11 million after-tax. The decrease in profits is also due to the impact of the retroactive Service Company allocation in 2003.

The Company is exploring strategic alternatives regarding the Fuels' coal mining business, which could include divesting these assets. As of December 31, 2004, the carrying value of long-lived assets of the coal mining business was $66 million. The Company cannot currently predict the outcome of this matter.

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)	2004	2003	2002
Total revenues	**$240**	$170	$92
Gross margin			
In millions of $	**$158**	$141	$83
As a % of revenues	**66%**	83%	90%
Segment profits (losses)	**$(4)**	$20	$27

CCO's operations generated segment losses of $4 million in 2004 compared to segment 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. Expenses were favorably impacted by a reduction in Service Company allocations. Results for 2003 were negatively impacted by the retroactive reallocation of Service Company costs of $3 million ($2 million after-tax).

CCO's operations generated segment profits of $20 million in 2003 compared to segment profits of $27 million in 2002. The increase in revenue for 2003 when compared to 2002 is primarily due to increased contracted capacity on newly constructed plants, energy revenue from a new, full-requirements power supply contract and a tolling agreement termination payment received during the first quarter. Generating capacity increased from 1,554 MW at December 31, 2002, to 3,100 MW at December 31, 2003, with the Effingham, Rowan Phase 2 and Washington plants being placed in service in 2003. In the second quarter of 2003, PVI acquired from Williams Energy Marketing and Trading a full-requirements power supply agreement with Jackson Electric Membership Corporation in Georgia for $188 million, which resulted in additional revenues of $21 million when compared to the same periods in 2002. The revenue increases related to higher volumes were partially offset by higher depreciation costs of $22 million, increased interest charges of $16 million and other fixed charges.

The Company has contracts for its planned production capacity, which includes callable resources from the cooperatives, of approximately 77% for 2005, approximately 81% for 2006 and approximately 75% for 2007. The Company continues to seek opportunities to optimize its nonregulated generation portfolio.

Rail Services

Rail Services' (Rail) operations represent the activities of Progress Rail and include railcar and locomotive repair, track-work, rail parts reconditioning and sales, scrap metal recycling, railcar leasing and other rail-related services.

Rail contributed segment profits of $16 million for 2004 compared with segment losses of $1 million and $42 million for the years ended December 31, 2003, and 2002, respectively. Results in 2004 were favorably impacted by the strong scrap metal market in 2004. Revenues were $1.131 billion in 2004, which represents an increase of $284 million compared to prior year. This increase is due primarily to increased volumes and higher prices in recycling operations and in part to increased production and sales in locomotive and railcar services and engineering and track services. Tonnage for recycling operations is up approximately 35% on an annualized basis compared to 2003. The increase in tonnage, coupled with an increase in the average index price of approximately 80%, accounts for the significant increase in revenues year over year. The American Metal Market index price for #1 railroad heavy melt (which is used as the index for buying and selling of railcars) has increased to $191 as of December 31, 2004, from $106 as of December 31, 2003. Cost of goods sold was $990 million in 2004, which represents an increase of $252 million compared to the prior year. The increase in costs of goods sold is due to increased costs for inventory, labor and operations as a result of the increased volume in the recycling operations, locomotive and railcar services and engineering and track services. In addition, results in 2003 were negatively impacted by the retroactive reallocation of Service Company costs of $3 million after-tax. The favorability related to the reallocation was offset by an increase in general and administrative costs in 2004 related primarily to higher professional fees associated with divestiture efforts. See discussion below.

Rail's operations generated segment losses of $1 million in 2003 compared to segment losses of $42 million in 2002. The reduction in losses in 2003 compared to 2002 is due primarily to an impairment charge recorded in 2002. The net loss in 2002 includes a $40 million after-tax estimated impairment of assets held for sale related to Railcar Ltd., a leasing subsidiary of Progress Rail (See Note 4D). Excluding the impairment recorded in 2002, profits for Rail were flat year over year 2003 compared to 2002.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 24 for more information.

Corporate & Other

Corporate and Other consists of the operations of Progress Energy Holding Company (the holding company), Progress Energy Service Company and other consolidating and nonoperating entities. Corporate and Other also includes other nonregulated business areas including the operations of SRS and the telecommunication operations.

OTHER NONREGULATED BUSINESS AREAS

Progress Energy's other 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, the Company 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, PTC and Caronet, both wholly owned telecommunication subsidiaries of Progress Energy, and EPIK, a wholly owned subsidiary of Odyssey, contributed substantially all of their assets and transferred certain liabilities to PT LLC, a subsidiary of PTC. The accounts of PT LLC have been included in the Company's Consolidated Financial Statements since the transaction date. See additional discussion on the telecommunication business combination in Note 5A.

Other nonregulated business areas contributed segment losses of $38 million compared to losses of $24 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 San Francisco United School District (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 Progress **Energy** Solutions. 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 prior year is due to an increase in fixed costs, mainly depreciation expense, and professional fees related to the merger with EPIK. The increased losses at SRS and telecommunication operations were offset partially by a reduction in losses at the nonutility subsidiaries of PEC. The nonutility subsidiaries of PEC contributed segment losses of $6 million and $18 million for the years ended December 31, 2004, and 2003, respectively. Included in the 2003 segment losses is an investment impairment of $6 million after-tax on the Affordable Housing portfolio held by the nonutility subsidiaries of PEC (See Note 10B). A reduction in investment losses accounted for the remaining favorability compared to prior year.

Other nonregulated business areas contributed segment losses of $24 million in 2003 compared to $250 million for the year ended December 31, 2002. The 2002 segment losses include an asset impairment and other charges in the telecommunications business of $225 million after-tax. See discussion of impairments at Note 10 of the Consolidated Financial Statements.

CORPORATE SERVICES

Corporate Services (Corporate) includes the operations of the holding company, Progress Energy Service Company and other consolidating and nonoperating entities, as summarized below:

Income (Expense) *(in millions)*	**2004**	Change	2003	Change	2002
Other interest expense	**$(270)**	$15	$(285)	$(10)	$(275)
Contingent value obligations	**9**	18	(9)	(37)	28
Tax reallocation	**(37)**	1	(38)	18	(56)
Other income taxes	**102**	(22)	124	11	113
Other income (expense)	**(2)**	19	(21)	(16)	(5)
Segment loss	**$(198)**	$31	$(229)	$(34)	$(195)

The other interest expense decrease for 2004 compared to 2003 is partially due to the repayment of a $500 million unsecured note by the Holding Company 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. Interest expense increased $10 million in 2003 compared to 2002 due to a decrease of $9 million in the amount of interest capitalized related to the construction of plants by CCO which was completed in 2003.

Progress Energy issued 98.6 million contingent value obligations (CVOs) in connection with the acquisition of FPC in 2000. Each CVO represents the right 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, 2004, 2003 and 2002, the CVOs had a fair market value of approximately $13 million, $23 million and $14 million, respectively. Progress Energy recorded unrealized losses of $9 million for 2003 and an unrealized gain of $9 million and $28 million for 2004 and 2002, respectively, to record the changes in fair value of CVOs, which

had average unit prices of $0.14, $0.23 and $0.14 at December 31, 2004, 2003 and 2002, 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. Progress Energy tax benefits not related to acquisition interest expense are allocated to profitable subsidiaries, beginning in 2002, in accordance with a Public Utility Holding Company Act of 1935, as amended (PUHCA) order.

Other income taxes benefit decreased for 2004 compared to 2003 due primarily to increased taxes booked at the Holding Company of $21 million. Income taxes increased an additional $9 million at the Holding Company as a result of a reserve booked related to identified state tax deficiencies. Other income taxes benefit decreased for 2003 compared to 2002 primarily for the tax allocation to the profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Discontinued Operations

In 2002, the Company approved the sale of NCNG to Piedmont Natural Gas Company, Inc. As a result, the operating results of NCNG were reclassified to discontinued operations for all reportable periods. In September 2003, Progress Energy completed the sale of NCNG and ENCNG for net proceeds of approximately $450 million in September 2003. Progress Energy incurred a loss from discontinued operations of $8 million for 2003 compared with a loss of $24 million for 2002. During the year ended December 31, 2004, the Company recorded a reduction to the loss on the sale of NCNG of approximately $6 million related to deferred taxes (See Note 4E).

Cumulative Effect of Accounting Change:

In 2003, Progress Energy recorded adjustments for the cumulative effects of changes in accounting principles due to the adoption of several new accounting pronouncements. These adjustments totaled to a $21 million loss after-tax, which was due primarily to new Financial Accounting Standards Board (FASB) guidance related to the accounting for certain contracts. This guidance discusses whether the pricing in a contract that contains broad market indices qualifies for certain exceptions that would not require the contract to be recorded at its fair value. PEC Electric had a purchase power contract with Broad River LLC that did not meet the criteria for an exception, and a negative fair value adjustment was recorded in 2003 for $23 million after-tax (See Note 18A).

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Company prepared its Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States. In doing so, certain estimates were made that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on the financial results of the Company and are subject to the greatest amount of subjectivity. Senior management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Company's Board of Directors.

Utility Regulation

As discussed in Note 8, the Company's regulated utilities segments are subject to regulation that sets the prices (rates) the Company is permitted to charge customers based on the costs that regulatory agencies determine the Company is 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 rate-making process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the changing regulatory framework in each state in which the Company operates, a significant amount of regulatory assets has been recorded. The Company continually reviews 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. Note 8 provides additional information related to the impact of utility regulation on the Company.

Asset Impairments

As discussed in Note 10, the Company evaluates the carrying value of long-lived assets for impairment 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, 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. A high degree of judgment is required in developing estimates related to these evaluations and various factors are considered, including projected revenues and cost and market conditions.

Due to the reduction in coal production at the Kentucky May coal mine, the Company evaluated its long-lived assets in 2003 and recorded an impairment of $17 million before tax ($11 million after-tax). Fair value was determined based on discounted cash flows. During 2002, the Company recorded pre-tax long-lived asset impairments of $305 million related to its telecommunications business. 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.

The Company continually reviews its investments to determine whether a decline in fair value below the cost basis is other than temporary. In 2003, PEC's affordable housing investment (AHI) portfolio was reviewed and 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. As a result, PEC recorded an impairment of $18 million on a pre-tax basis during 2003. PEC also recorded an impairment of $3 million for a cost investment. During 2002, the Company recorded pre-tax impairments to its cost method investment in Interpath of $25 million. The fair value of this investment was determined considering various factors, including a valuation study heavily weighted on a discounted cash flow methodology and using market approaches as supporting information. These cash flows included numerous assumptions, including the pace at which the telecommunications market would rebound. In the fourth quarter of 2002, the Company sold its remaining interest in Interpath for a nominal amount.

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, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2004, 2003 or 2002.

Goodwill

As discussed in Note 9, effective January 1, 2002, the Company adopted FASB Statement No. 142, "Goodwill and Other Intangible Assets," which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. The Company completed the initial transitional goodwill impairment test, which indicated that the Company's goodwill was not impaired as of January 1, 2002. The Company performed the annual goodwill impairment test for the CCO segment in the first quarters of 2004 and 2003, and the annual goodwill impairment test for the PEC Electric and PEF segments in the second quarters of 2004 and 2003, each of which indicated no impairment. If the fair values for the utility segments were lower by approximately 10%, there still would be no impact on the reported value of their goodwill. The carrying amounts of goodwill at December 31, 2004, and 2003, for reportable segments PEC Electric, PEF and CCO, are $1,922 million, $1,733 million and $64 million, respectively. In December 2003, $7 million in goodwill was acquired as part of Progress Telecommunications Corporation's partial acquisition of EPIK and was reported in the Corporate and Other segment. The Company 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.

Synthetic Fuels Tax Credits

As discussed in Note 23E, Progress Energy, through the Fuels business unit, owns facilities that produce synthetic fuels 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 if certain requirements are satisfied, including a requirement that the synthetic fuels differs significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility placed in service before July 1, 1998. The amount of Section 29 credits that the Company is allowed to claim in any calendar year is limited by the amount of

the Company's regular federal income tax liability. Synthetic fuels tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits on the Consolidated Balance Sheets. All of Progress Energy's synthetic fuel facilities have received PLRs from the IRS with respect to their operations, although these do not address placed-in-service date determinations. The PLRs do not limit the production on which synthetic fuel credits may be claimed. The current Section 29 tax credit program expires at the end of 2007. These tax credits are subject to review by the IRS, and if Progress Energy fails to prevail through the administrative or legal process, there could be a significant tax liability owed for previously taken Section 29 credits, with a significant impact on earnings and cash flows. Additionally, the ability to use tax credits currently being carried forward could be denied. See further discussion in "OTHER MATTERS" below, and Note 23E.

Pension Costs

As discussed in Note 17A, Progress Energy maintains qualified noncontributory defined benefit retirement (pension) plans. The Company's 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, the Company lowered the discount rate to 5.9% at December 31, 2004, which will increase the 2005 benefit costs recognized, all other factors remaining constant. Plan assets performed well in 2004, with returns of approximately 14%. That positive asset performance will result in decreased pension costs in 2005, all other factors remaining constant. Evaluations of the effects of these and other factors have not been completed, but the Company estimates that the total cost recognized for pensions in 2005 will be approximately $12 million to $20 million higher than the amount recorded in 2004.

The Company has pension plan assets with a fair value of approximately $1.8 billion at December 31, 2004. The Company's expected rate of return on pension plan assets is 9.25%. The Company reviews this rate on a regular basis. Under Statement of Financial Accounting Standards 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, the Company would adjust that return only if its fundamental assessment of the debt and equity markets changes or its investment policy changes significantly. The Company believes that its pension plans' asset investment mix and historical performance support the long-term rate of 9.25% being used. The Company did not adjust the rate in response to short-term market fluctuations such as the abnormally high market return levels of the latter 1990s, recent years' market declines and the market rebound in 2003 and 2004. A 0.25% change in the expected rate of return for 2004 would have changed 2004 pension costs by approximately $4 million.

Another factor affecting the Company's 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 9.25% 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. The Company has historically used a five-year averaging method. When the Company acquired Florida Progress Corporation (Florida Progress) in 2000, it 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. For example, in 2004 the expected return for assets subject to the averaging method was 2% lower than in 2003, whereas the expected return for assets subject to the fair value method was 24% higher than in 2003. Approximately 50% of the Company's pension plan assets is subject to each of the two methods.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Progress Energy is a registered holding company and, as such, has no operations of its own. The Company's primary cash needs at the holding company level are its common stock dividend and interest expense and principal payments on its $4.3 billion of senior unsecured debt. The

ability to meet these needs is dependent on the earnings and cash flows of its two electric utilities and nonregulated subsidiaries, and the ability of those subsidiaries to pay dividends or repay funds to Progress Energy.

Other significant cash requirements of the Company arise primarily from the capital-intensive nature of its electric utility operations and expenditures for its diversified businesses, primarily those of the Fuels segment.

The Company relies upon its operating cash flow, primarily generated by its two regulated electric utility subsidiaries, commercial paper and bank facilities, and its ability to access long-term debt and equity capital markets for sources of liquidity.

The majority of the Company's operating costs are related to its two regulated electric utilities, and a significant portion of these costs is recovered from customers through fuel and energy cost recovery clauses.

Other significant uses of liquid resources include debt interest and principal payments, capital expenditures and dividends on preferred and common stock.

As a registered holding company under PUHCA, Progress Energy obtains 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 and borrow between each other. A nonutility money pool allows Progress Energy's nonregulated operations to lend and borrow funds among each other. Progress Energy can lend money to the utility and nonutility money pools but cannot borrow funds.

Cash from operations, asset sales and the issuance of common stock are expected to fund capital expenditures and common dividends for 2005. Any excess cash proceeds would be used to reduce debt. To the extent necessary, short- and long-term debt may also be used as a source of liquidity.

The Company believes its internal and external liquidity resources will be sufficient to fund its current business plans.

The following discussion of the Company's liquidity and capital resources is on a consolidated basis.

Historical for 2004 as compared to 2003 and 2003 as compared to 2002

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, 2004, 2003 and 2002 were $1.6 billion, $1.7 billion and $1.6 billion, respectively.

Cash from operating activities for 2004 when compared with 2003 decreased $117 million, as the net result of the impact of hurricane costs, partially offset by the impact of an underrecovery of fuel costs in 2003. The increase in cash from operating activities for 2003 when compared with 2002 is largely the result of improved operating results at PEC.

During the third quarter of 2004, four hurricanes struck significant portions of the Company's service territories, with the most significant impact on PEF's territory. Restoration of the Company's systems from storm-related damage cost an estimated $398 million. PEC's cost totaled $13 million, of which $12 million was charged to O&M and $1 million was charged to capital. PEF's cost totaled $385 million, of which $338 million was charged to Storm Damage Reserve pursuant to a regulatory order and $47 million was charged to capital. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail rate payers over a two-year period (See Note 3).

Progress Energy is allowed to recover fuel costs incurred by PEC and PEF through their respective fuel cost recovery surcharges. Fuel price volatility can lead to over- or underrecovery 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 drag on liquidity resources, depending on what phase of the cycle of price volatility the Company is experiencing. In addition, in 2004 PEF agreed with the FPSC to use a two-year period to determine the surcharge for the underrecovered fuel costs incurred in 2004 (See Note 8C).

Investing Activities

Net cash used in investing activities for the three years ending December 31, 2004, 2003 and 2002 were $0.9 billion, $1.5 billion and $2.2 billion, respectively.

Utility property additions for the Company's regulated electric operations were $1.0 billion or approximately 75% of consolidated capital expenditures in 2004 and $1.0 billion or approximately 58% of consolidated capital expenditures in 2003, excluding proceeds from asset sales. Capital expenditures for the regulated electric operations are primarily for normal construction activity and ongoing capital expenditures related to environmental compliance programs. Capital expenditures for the 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 decreased approximately $887 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 short-term investments in 2004, compared to net purchases of short-term investments in 2003.

Excluding proceeds from sales of subsidiaries and other investments, cash used in investing activities was $2.1 billion in 2003, down approximately $119 million when compared with 2002. The decrease is due primarily to lower utility property additions due to completion of Hines 2 construction at PEF and lower acquisitions of nonregulated assets.

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. Progress Energy used the proceeds from these sales to reduce indebtedness, including $241 million to pay off the Progress Genco Ventures, LLC, bank facility.

During 2003, the Company realized approximately $450 million of net cash proceeds from the sale of NCNG and ENCNG. The Company also received net proceeds of approximately $97 million in October 2003 for the sale of its Mesa gas properties in Colorado. Progress Energy used the proceeds from these sales to reduce indebtedness, primarily commercial paper, then outstanding.

During 2003, the Company acquired approximately 200 natural gas–producing wells for a cash purchase price of $168 million. The Company also acquired a long-term full-requirements power supply agreement with Jackson Electric Membership Corporation for a cash payment of $188 million.

During 2002, the Company purchased two electric generation projects for a cash purchase price of $348 million.

Financing Activities

Net cash provided by financing activities for the three years ending December 31, 2004, 2003 and 2002 were $(720) million, $(192) million and $581 million, respectively. See Note 13 for details of debt and credit facilities.

For 2004 and 2003, cash from operations exceeded net cash used in investing activities by $735 million and $178 million, respectively, due primarily to asset sales, which allowed for a net decrease in cash provided by financing activities. For 2002, net cash used in investing activity exceeded cash from operations by $574 million, which resulted in net cash from financing activities of $581 million.

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

2005

- In March 2005, Progress Energy, Inc.'s five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65% to 68% in anticipation of the potential impacts of proposed accounting rules for uncertain tax positions. See Notes 2 and 23E.
- On January 31, 2005, Progress Energy, Inc. entered into a new $600 million revolving credit agreement, which expires December 30, 2005. This facility was added to provide additional liquidity during 2005 due in part to the uncertainty of the timing of storm restoration cost recovery from the hurricanes in Florida during 2004. The credit agreement includes a defined maximum total debt to total capital ratio of 68% and a minimum interest coverage ratio of 2.5 to 1. The credit agreement also contains various cross-default and other acceleration provisions. On February 4, 2005, $300 million was drawn under the new facility to reduce commercial paper and pay off the remaining amount of RCA loans outstanding.
- In January 2005, the Company used proceeds from the issuance of commercial paper to pay off $260 million of revolving credit agreement (RCA) loans.

2004

- During the fourth quarter of 2004, Progress Energy and its subsidiaries PEC and PEF borrowed a net total of $475 million under certain revolving credit facilities. The borrowed funds were used to pay off maturing

commercial paper and for other cash needs. A summary of RCA loans and available capacity as of December 31, 2004 is as follows:

(in millions)				
Company	Description	Total	Outstanding	Available
Progress Energy, Inc.	5-Year (expiring 8/5/09)	$1,130	$160	$970
Progress Energy Carolinas, Inc.	364-Day (expiring 7/27/05)	165	90	75
Progress Energy Carolinas, Inc.	3-Year (expiring 7/31/05)	285	–	285
Progress Energy Florida, Inc.	364-Day (expiring 3/29/05)	200	170	30
Progress Energy Florida, Inc.	3-Year (expiring 4/01/06)	200	55	145
Less: amounts reserved[a]		–	–	(574)
Total credit facilities		$1,980	$475	$931

[a] To the extent amounts are reserved for commercial paper outstanding or backing letters of credit, they are not available for additional borrowings.

- On December 17, 2004, the Company used proceeds from the sale of natural gas assets to extinguish Progress Genco Ventures, LLC's $241 million bank facility (See Note 13D).
- Progress Energy took advantage of favorable market conditions and entered into a new $1.1 billion five-year line of credit, effective August 5, 2004, and 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.
- On July 28, 2004, PEC extended its $165 million 364-day line of credit, which was scheduled to expire on July 29, 2004. The line of credit will expire on July 27, 2005.
- On July 1, 2004, PEF paid at maturity $40 million 6.69% Medium-Term Notes Series B with commercial paper proceeds and cash from operations.
- On April 30, 2004, PEC redeemed $35 million of Darlington County 6.6% Series Pollution Control Bonds at 102.5% of par, $2 million of New Hanover County 6.3% Series Pollution Control Bonds at 101.5% of par, and $2 million of Chatham County 6.3% Series Pollution Control Bonds at 101.5% of par with cash from operations.
- On March 1, 2004, Progress Energy used available cash and proceeds from the issuance of commercial paper to pay at maturity $500 million 6.55% senior unsecured notes. Cash and commercial paper capacity for this retirement was created primarily from proceeds of the sale of assets in 2003.
- On February 9, 2004, Progress Capital Holdings, Inc., paid at maturity $25 million 6.48% medium-term notes with available cash from operations.
- On January 15, 2004, PEC paid at maturity $150 million 5.875% First Mortgage Bonds with commercial paper proceeds. On April 15, 2004, PEC also paid at maturity $150 million 7.875% First Mortgage Bonds with commercial paper proceeds and cash from operations.
- For 2004, the Company issued approximately 1 million shares of its common stock for approximately $73 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 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 Energy issued approximately 8 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.
- 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 Capital Holdings, Inc., paid at maturity $58 million in medium-term notes.
- Progress Genco Ventures, LLC, terminated its $50 million working capital credit facility. Under its related construction facility, Genco had drawn $241 million at December 31, 2003.

2002

- Progress Energy issued $800 million in senior unsecured notes. Progress Energy issued approximately 2 million shares representing approximately $86 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit plans.
- PEC issued and redeemed $500 million in senior unsecured notes and $48.5 million in pollution control obligations. PEC also redeemed $150 million and paid at maturity $100 million in first mortgage bonds.

- PEF issued and redeemed $241 million in pollution control obligations and paid at maturity $30 million in medium-term notes.
- Progress Capital Holdings, Inc., paid at maturity $50 million in medium-term notes.
- Progress Genco Ventures, LLC, obtained a $440 million bank facility, including $50 million for working capital. During the year, $130 million of the facility was terminated. The amount outstanding at December 31, 2002, was $225 million.
- In November 2002, the Company issued 14.7 million shares of common stock for net cash proceeds of approximately $600 million, which were primarily used to retire commercial paper. For 2002, the dividends paid on common stock were approximately $480 million.

Future liquidity and capital resources

The Company's two electric utilities produced over 100% of consolidated cash from operations in 2004. It is expected that the two electric utilities will continue to produce a majority of the consolidated cash flows from operations over the next several years as its nonregulated investments, primarily generation assets, improve asset utilization and increase their operating cash flows.

PEF notified the FPSC in January 2005 of its intent to file for an increase in its base rates effective January 1, 2006. If approved by the FPSC, an increase in PEF's base rates would increase future operating cash flows. PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines 3 generation facility, extraordinary hurricane damage costs including capital costs not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of strong customer growth. If the FPSC does not approve PEF's request to increase base rates, the Company's results of operations and financial condition could be negatively impacted. The Company cannot predict the outcome of this matter.

In addition, Fuels' 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 23E for further discussion.

Capital Expenditures

Total cash from operations provided the funding for the Company's capital expenditures, including property additions, nuclear fuel expenditures and diversified business property additions during 2004, excluding proceeds from asset sales of $366 million.

As shown in the table below, Progress Energy expects the majority of its capital expenditures to be incurred at its regulated operations. See Note 8F for a discussion of expected impacts on future capital expenditures due to changes in capitalization practice for regulated operations. The Company anticipates its regulated capital expenditures will increase in 2005 due to increased spending on Clean Air initiatives. Forecasted nonregulated expenditures relate primarily to Progress Fuels and its gas operations, mainly for drilling new wells.

	Actual	Forecasted		
(in millions)	**2004**	2005	2006	2007
Regulated capital expenditures	**$998**	$1,030	$1,040	$1,090
Nuclear fuel expenditures	**101**	120	90	150
AFUDC – borrowed funds	**(6)**	(10)	(10)	(10)
Nonregulated capital expenditures	**236**	190	180	190
Total	**$1,329**	$1,330	$1,300	$1,420

Regulated capital expenditures in the table above include total expenditures from 2005 through 2006 of approximately $65 million expected to be incurred at PEC fossil-fueled electric generating facilities to comply with Section 110 of the Clean Air Act, referred to as the NOx SIP Call.

The Company also expects to incur expenditures of approximately $15 million ($10 million at PEC and $5 million at PEF) from 2005 through 2007 and additional expenditures of approximately $70 million to $100 million ($10 million to $20 million at PEC and $60 million to $80 million at PEF) from 2008 through 2009 for compliance with the Section 316(b) requirements of the Clean Water Act (See Note 22).

In June 2002, legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired power plants. PEC expects its capital costs to meet these emission targets will be approximately $895 million by 2013. For the years 2005 through 2007, the Company expects to incur approximately $475 million of total capital costs

associated with this legislation, which is included in the table above (See Note 22).

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

As of December 31, 2004, on a consolidated basis, the Company had $349 million of long-term debt maturing in 2005. Progress Energy expects to pay these maturities using funds from operations, issuance of new long-term debt, commercial paper borrowings and/or issuance of new equity securities.

In 2006, $800 million of Progress Energy senior unsecured notes will mature. The Company expects to fund the maturity using proceeds from the sale of the Progress Rail subsidiary, issuance of new long-term debt, commercial paper borrowings and/or issuance of new equity securities.

During the fourth quarter of 2004, Progress Energy announced the launch of a new cost-management initiative aimed at achieving nonfuel O&M expense reductions of $75 million to $100 million annually by the end of 2007. In connection with this cost-management initiative, the Company expects to incur one-time pre-tax charges of approximately $130 million. Approximately $30 million of that amount relates to payments for severance benefits, which will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $100 million will be recognized in the second quarter of 2005 and relates primarily to postretirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program (See Note 24).

Credit Facilities

At December 31, 2004, the Company and its subsidiaries had committed lines of credit and outstanding balances as shown in the table in Note 13. All of the credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities.

The Company's financial policy precludes issuing commercial paper in excess of its supporting lines of credit. At December 31, 2004, the Company had $424 million of commercial paper outstanding, $150 million reserved for backing of letters of credit and an additional $475 million drawn directly from the credit facilities, leaving $931 million available for issuance or drawdown. In addition, the Company has requirements to pay minimal annual commitment fees to maintain its credit facilities. At December 31, 2003, the Company had $4 million of commercial paper outstanding. The Company expects to continue to use commercial paper issuances as a source of liquidity as long as it maintains its current short-term ratings.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage) and coverage ratios. The Company is in compliance with these covenants at December 31, 2004. See Note 13 for a discussion of the credit facilities' financial covenants, material adverse change clause provisions and cross-default provisions. At December 31, 2004, the calculated ratios for the companies, pursuant to the terms of the agreements, are as disclosed in Note 13.

Both PEC and PEF plan to enter into new five-year lines of credit in 2005 to replace their existing credit facilities.

The Company has on file with the SEC a shelf registration statement under which senior notes, junior debentures, common and preferred stock and other trust preferred securities are available for issuance by the Company. At December 31, 2004, the Company had approximately $1.1 billion available under this shelf registration.

Progress Energy and PEF each have an uncommitted bank bid facility authorizing each of them to borrow and reborrow, and have loans outstanding at any time, up to $300 million and $100 million, respectively. At December 31, 2004, there were no outstanding loans against these facilities.

PEC currently has on file with the SEC a shelf registration statement under which it can issue up to $900 million of various long-term securities. PEF currently has on file registration statements under which it can issue an aggregate of $750 million of various long-term debt securities.

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2004, PEC and PEF could issue up to $2.9 billion and $3.7 billion, respectively, based on property additions and $2.2 billion and $176 million, respectively, based upon retirements.

The following table shows Progress Energy's capital structure at December 31:

	2004	2003
Common stock	**41.7%**	40.5%
Preferred stock and minority interest	**0.7%**	0.7%
Total debt	**57.6%**	58.8%

The amount and timing of future sales of company securities will depend on market conditions, operating cash flow, asset sales and the specific needs of the Company. The Company 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.

Credit Rating Matters

The major credit rating agencies have currently rated the Company's securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Progress Energy, Inc.			
Outlook	Negative	Negative	Stable
Corporate credit rating	n/a	BBB	n/a
Senior unsecured debt	Baa2	BBB-	BBB-
Commercial paper	P-2	A-3	n/a
Progress Energy Carolinas, Inc.			
Corporate credit rating	n/a	BBB	n/a
Commercial paper	P-2	A-3	F2
Senior secured debt	A3	BBB	A-
Senior unsecured debt	Baa1	BBB	BBB+
Progress Energy Florida, Inc.			
Corporate credit rating	**n/a**	**BBB**	**n/a**
Commercial paper	**P-2**	A-3	**F2**
Senior secured debt	**A2**	**BBB**	**A-**
Senior unsecured debt	**A3**	**BBB**	**BBB+**
FPC Capital I			
Preferred stock*	Baa2	BB+	n/a
Progress Capital Holdings, Inc.			
Senior unsecured debt*	Baa1	BBB-	n/a

*Guaranteed by Florida Progress Corporation.

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, the Company monitors its financial condition as well as market conditions that could ultimately affect its credit ratings.

On February 11, 2005, Moody's credit rating agency announced that it lowered the ratings of PEF, Progress Capital Holdings 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 upcoming rate case in Florida and ongoing capital requirements to meet Florida's growing demand.

On October 19, 2004, S&P changed Progress Energy's outlook from stable to negative. S&P cited the uncertainties regarding the timing of the recovery of hurricane costs, the Company's debt reduction plans and the IRS audit of the Company's Earthco synthetic fuels facilities as the reasons for the change in outlook. On October 25, 2004, S&P reduced the short-term debt rating of Progress Energy, PEC and PEF to A-3 from A-2, as a result of their change in outlook discussed above.

On October 20, 2004, Moody's changed its outlook for Progress Energy from stable to negative and placed the ratings of PEF under review for possible downgrade. PEC's ratings were affirmed by Moody's.

Moody's cited the following reasons for its change in the outlook for Progress Energy: financial ratios that are weak for its current rating category; rising O&M, pension, benefit and insurance costs; and delays in executing its deleveraging plan. With respect to PEF, Moody's cited declining cash flow coverages and rising leverage over the last several years, expected funding needs for a large capital expenditure program, risks with regard to its upcoming 2005 rate case and the timing of hurricane cost recovery as reasons for putting its ratings under review.

The changes by S&P and Moody's do not trigger any debt or guarantee collateral requirements, nor do they have any material impact on the overall liquidity of Progress Energy or any of its affiliates. 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. However, the changes have increased the interest rate incurred on its short-term borrowings by 0.25% to 0.875%.

If Standard & Poor's 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 to increase borrowing costs. The Company's liquidity would essentially remain unchanged, as the Company believes it could borrow under its revolving credit facilities instead of issuing commercial paper for its short-term borrowing needs. However, there would be additional funding requirements of approximately $450 million due to ratings triggers embedded in various contracts, as more fully described below under "Guarantees."

The Company and its subsidiaries' 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. However, in the event of a downgrade, the Company and/or its subsidiaries may be subject to increased interest costs on the credit facilities backing up the commercial paper programs. In addition, the Company and its subsidiaries have certain contracts that have provisions triggered by a ratings downgrade to a rating below investment grade. These contracts include counterparty trade agreements, derivative contracts, certain Progress Energy guarantees and various types of third-party purchase agreements.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

The Company's off-balance sheet arrangements and contractual obligations are described below.

Guarantees

As a part of normal business, Progress Energy and certain wholly owned subsidiaries enter into various agreements providing future financial or performance assurances to third parties that are outside the scope of Financial Accounting Standards Board (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 and subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. The Company's guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. The Company's guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2004, the Company had issued $1.3 billion of guarantees for future financial or performance assurance. Management does 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), ratings triggers, monthly netting of exposure and/or payments and offset provisions in the event of a default. The recent outlook changes from S&P and Moody's do not trigger any guarantee obligations. As of December 31, 2004, if the guarantee obligations were triggered, the maximum amount of liquidity requirements to support ongoing operations within a 90-day period, associated with guarantees for the Company's nonregulated portfolio and power supply agreements, was $450 million. The Company would meet this obligation with cash or letters of credit.

As of December 31, 2004, Progress Energy had guarantees issued on behalf of third parties of approximately $10 million. See Note 23D for a discussion of guarantees in accordance with FIN No. 45.

Market Risk and Derivatives

Under its risk management policy, the Company 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 and "Quantitative and Qualitative Disclosures about Market Risk" for a discussion of market risk and derivatives.

Contractual Obligations

The Company is party to numerous contracts and arrangements obligating it 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 will likely differ from amounts presented below. Further disclosure regarding the Company's contractual obligations is included in the respective notes. The Company takes into consideration the future commitments following when assessing its

liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2004, 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 13)	$9,942	$349	$1,637	$1,387	$6,569
Interest payments on long-term debt and interest rate derivatives[b]	3,064	301	489	423	1,851
Capital lease obligations (See Note 23C)	50	4	8	7	31
Operating leases (See Note 23C)	597	66	113	112	306
Fuel and purchased power[c] (See Note 23A)	13,010	2,692	3,088	1,346	5,884
Other purchase obligations (See Note 23A)	633	151	134	80	268
North Carolina Clean Air capital commitments (See Note 22)	764	170	297	143	154
Other commitments[d][e]	243	42	70	26	105
Total	$28,303	$3,775	$5,836	$3,524	$15,168

[a] The Company's maturing debt obligations are generally expected to be refinanced with new debt issuances in the capital markets. However, the Company does plan to annually reduce its debt to total capitalization leverage over the next few years through selected asset sales, free cash flow and increased equity from retained earnings and ongoing equity issuances.

[b] Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective as of December 31, 2004, and the LIBOR forward curve as of December 31, 2004, respectively.

[c] Fuel and purchased power commitments represent the majority of the Company's remaining future commitments after its debt obligations. Essentially all of the Company's 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] 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% must be transitioned each year.

[e] The Company has certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties) through 2007 (See Note 23B).

OTHER MATTERS

Synthetic Fuels Tax Credits

The Company has 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 numerous risks.

Although the Company believes that it operates its synthetic fuel facilities in compliance with applicable legal requirements for claiming the credits, its four Earthco facilities are under audit by the IRS. IRS field auditors have taken an adverse position with respect to the Company's compliance with one of these legal requirements, and if the Company fails to prevail with respect to this position, it could incur significant liability and/or lose the ability to claim the benefit of tax credits carried forward or generated in the future. Similarly, the Financial Accounting Standards Board may issue new accounting rules that would require that uncertain tax benefits (such as those associated with the Earthco plants) be probable of being sustained in order to be recorded on the financial statements; if adopted, this provision could have an adverse financial impact on the Company.

The Company's ability to utilize tax credits is dependent on having sufficient tax liability. Any conditions that negatively impact the Company's tax liability, such as weather, could also diminish the Company's ability to utilize credits, including those previously generated, and the synthetic fuel is generally not economical to produce absent the credits. Finally, the tax credits associated with synthetic fuels may be phased out if market prices for crude oil exceed certain prices.

The Company's synthetic fuel operations and related risks are described in more detail in Note 23E.

Hurricane Costs

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of the Company's service territories during the third quarter of 2004, significantly impacting PEF's territory. As of December 31, 2004, restoration of the Company's systems from hurricane-related damage was estimated at $398 million. PEC incurred restoration costs of $13 million, of which $12 million was charged to operation and maintenance expense and $1 million was charged to capital expenditures. PEF had estimated total costs of $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions. As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Storm reserve costs of $13 million were attributable to wholesale customers. The Company has received approval from the FERC to amortize these costs consistent with recovery of such amounts in wholesale rates. PEF continues to review the restoration cost invoices received. Given that not all invoices have been received as of December 31, 2004, PEF will update its petition with the FPSC upon receipt and audit of all actual charges incurred. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005.

On November 17, 2004, the Citizens of the State of Florida, by and through Harold McLean, Public Counsel, and the Florida Industrial Power Users Group (FIPUG) (collectively, Joint Movants) filed a Motion to Dismiss PEF's petition to recover the $252 million in storm costs. On November 24, 2004, PEF responded in opposition to the motion, which was also the FPSC staff's position in its recommendation to the Commission on December 21, 2004, that it should deny the Motion to Dismiss. On January 4, 2005, the Commission ruled in favor of PEF and denied the Joint Movant's Motion to Dismiss.

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period.

PEC does not have an ongoing regulatory mechanism to recover storm costs; therefore, hurricane restoration costs recorded in the third quarter of 2004 were charged to operations and maintenance expenses or capital expenditures based on the nature of the work performed. In connection with other storms, PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over a five-year period. PEC did not seek deferral of 2004 storm costs from the NCUC (See Note 8B).

Regulatory Environment and Matters

The Company's electric utility operations in North Carolina, South Carolina and Florida are regulated by the NCUC, the Public Service Commission of South Carolina (SCPSC) and the FPSC, respectively. The electric businesses are also subject to regulation by the FERC, the NRC and other federal and state agencies common to the utility business. In addition, the Company is 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 electric utilities are permitted to earn, are subject to the approval of governmental agencies.

PEC and PEF continue to monitor any developments toward a more competitive environment and have actively participated in regulatory reform deliberations in North Carolina, South Carolina and Florida. Movement toward deregulation in these states has been affected by recent developments, including developments related to deregulation of the electric industry in other states. The Company expects the legislatures in all three states will continue to monitor the experiences of states that have implemented electric restructuring legislation. The Company 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 8B and 8C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects to the Company's consolidated financial statements.

The regulatory authorities continue to evaluate issues related to the formation of Regional Transmission

Organizations. The Company cannot predict the outcome of these matters on the Company's earnings, revenues or prices or the investments in GridSouth and GridFlorida (See Note 8D)

A FERC order issued in November 2001 on certain unaffiliated utilities' triennial market-based wholesale power rate authorization updates required certain mitigation actions that those utilities would need to take for sales/purchases within their control areas and required those utilities to post information on their Web sites regarding their power systems' status. As a result of a request for rehearing filed by certain market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. 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. Management is unable to predict the outcome of these actions by the FERC or their effect on future results of operations and cash flows. 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 August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside PEC's control area and file a new cost-based tariff for sales within PEC's control area that incorporates the FERC's default cost-based rate methodologies for sales of one year or less. PEC anticipates making this filing in the first quarter of 2005. Although the Company cannot predict the ultimate outcome of these changes, the Company does not anticipate that the current operations of PEC or PEF would be impacted materially if they were unable to sell power at market-based rates in their respective control areas.

Franchise Litigation

Three cities, with a total of approximately 18,000 customers, have litigation pending against PEF in various circuit courts in Florida. As previously reported, three other cities, with a total of approximately 30,000 customers, have subsequently settled their lawsuits with PEF and signed new, 30-year franchise agreements. The lawsuits principally seek (1) a declaratory judgment that the cities have the right to purchase PEF's electric distribution system located within the municipal boundaries of the cities, (2) a declaratory judgment that the value of the distribution system must be determined through arbitration, and (3) injunctive relief requiring PEF to continue to collect from PEF's customers, and remit to the cities, franchise fees during the pending litigation, and as long as PEF continues to occupy the cities' rights-of-way to provide electric service, notwithstanding the expiration of the franchise ordinances under which PEF had agreed to collect such fees. The circuit courts in those cases have entered orders requiring arbitration to establish the purchase price of PEF's electric distribution system within five cities. Two appellate courts have upheld those circuit court decisions and authorized the cities to determine the value of PEF's electric distribution system within the cities through arbitration.

Arbitration in one of the cases (with the 13,000-customer City of Winter Park) was completed in February 2003. That arbitration panel issued an award in May 2003 setting the value of PEF's distribution system within the City of Winter Park (the City) at approximately $32 million, not including separation and reintegration and construction work in progress, which could add several million dollars to the award. The panel also awarded PEF approximately $11 million in stranded costs, which, according to the award, decrease over time. In September 2003, Winter Park voters passed a referendum that would authorize the City to issue bonds of up to approximately $50 million to acquire PEF's electric distribution system. While the City has not yet definitively decided whether it will acquire the system, on April 26, 2004, the City Commission voted to proceed with the acquisition. The City sought and received wholesale power supply bids and on June 24, 2004, executed a wholesale power supply contract with PEF. On May 12, 2004, the City solicited bids to operate and maintain the distribution system and awarded a contract in January 2005. The City has indicated that its goal is to begin electric operations in June 2005. On February 10, 2005, PEF filed a petition with the Florida Public Service Commission to relieve the Company of its statutory obligation to serve customers in Winter Park

on June 1, 2005, or at such time when the City is able to provide retail service. At this time, whether and when there will be further proceedings regarding the City of Winter Park cannot be determined.

Arbitration with the 2,500-customer Town of Belleair was completed in June 2003. In September 2003, the arbitration panel issued an award in that case setting the value of the electric distribution system within the Town at approximately $6 million. The panel further required the Town to pay to PEF its requested $1 million in separation and reintegration costs and $2 million in stranded costs. The Town has not yet decided whether it will attempt to acquire the system; however, on January 18, 2005, it issued a request for proposals for wholesale power supply and to operate and maintain the distribution system. Proposals are due in early March 2005. In February 2005, the Town Commission also voted to put the issue of whether to acquire the distribution system to a voter referendum on or before October 2, 2005. At this time, whether and when there will be further proceedings regarding the Town of Belleair cannot be determined.

Arbitration in the remaining city's litigation (the 1,500-customer City of Edgewood) has not yet been scheduled. On February 17, 2005, the parties filed a joint motion to stay the litigation for a 90-day period during which the parties will discuss potential settlement.

A fourth city (the 7,000-customer City of Maitland) is contemplating municipalization and has indicated its intent to proceed with arbitration to determine the value of PEF's electric distribution system within the City. Maitland's franchise expires in August 2005. At this time, whether and when there will be further proceedings regarding the City of Maitland cannot be determined.

As part of the above litigation, two appellate courts reached opposite conclusions regarding whether PEF must continue to collect from its customers and remit to the cities "franchise fees" under the expired franchise ordinances. PEF filed an appeal with the Florida Supreme Court to resolve the conflict between the two appellate courts. On October 28, 2004, the Court issued a decision holding that PEF must collect from its customers and remit to the cities franchise fees during the interim period when the city exercises its purchase option or executes a new franchise. The Court's decision should not have a material impact on the Company.

Legal

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

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. The nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications (See Notes 6 and 23E).

Environmental Matters

The Company is 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 the associated exposures to the Company. The Company accrues costs to the extent they are probable and can be reasonably estimated. It is reasonably possible 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

Market risk represents the potential loss arising from adverse changes in market rates and prices. Certain market risks are inherent in the Company's financial instruments, which arise from transactions entered into in the normal course of business. The Company's primary exposures are changes in interest rates with respect to its long-term debt and commercial paper, and fluctuations in the return on marketable securities with respect to its nuclear decommissioning trust funds. The Company manages its market risk in accordance with its established risk management policies, which may include entering into various derivative transactions.

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 the Company's operations, such as purchase and sales commitments and inventory.

Interest Rate Risk

The Company manages its interest rate risks through the use of a combination of fixed and variable rate debt. Variable rate debt has rates that adjust in periods ranging from daily to monthly. Interest rate derivative instruments may be used to adjust interest rate exposures and to protect against adverse movements in rates.

The following tables provide information at December 31, 2004 and 2003, about the Company's 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 the Company's 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 2005-2009 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.

(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.

(dollars in millions) December 31, 2003	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
Fixed rate long-term debt	$868	$349	$909	$674	$827	$5,836	$9,463	$10,501
Average interest rate	6.67%	7.38%	6.78%	6.41%	6.27%	6.51%	6.55%	
Variable rate long-term debt	–	–	–	$241	–	$861	$1,102	$1,103
Average interest rate	–	–	–	3.04%	–	1.08%	1.51%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$313
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives:								
Pay variable/receive fixed	–	–	$(300)	$(350)	$(200)	–	$(850)	$(4)
Average pay rate	–	–	(b)	(b)	(b)	–	(b)	
Average receive rate	–	–	2.75%	3.35%	2.93%	–	3.04%	
Payer swaptions	–	–	–	–	$400	–	$400	$5
Average pay rate	–	–	–	–	4.75%	–	–	
Average receive rate	–	–	–	–	(b)	–	–	
Interest rate collars[c]	$65	–	–	$130	–	–	$195	$(11)
Cap rate	6.00%	–	–	6.50%	–	–	–	
Floor rate	4.13%	–	–	5.13%	–	–	–	

(a) FPC Capital I – Quarterly Income Preferred Securities.
(b) Rate is 3-month LIBOR, which was 1.15% at December 31, 2003.
(c) Notional amount is varying with a maximum of $195 million, decreasing to $130 million after December 2004.

Marketable Securities Price Risk

The Company's electric utility subsidiaries 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. The fair value of these funds was $1.044 billion and $938 million at December 31, 2004 and 2003, respectively. The Company actively monitors its portfolio by benchmarking the performance of its 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 Company's 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 the earnings of the Company.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of FPC, the Company issued 98.6 million CVOs. Each CVO represents the right 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, 2004 and 2003, the fair value of these CVOs was $13 million and $23 million, respectively. A hypothetical 10% decrease in the December 31, 2004, market price would result in a $1 million decrease in the fair value of the CVOs.

Commodity Price Risk

The Company is 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 its ownership of energy-related assets. The Company's exposure to these fluctuations is significantly limited by the cost-based regulation of PEC and PEF. 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 the Company's long-term power sales contracts shift substantially all fuel responsibility to the purchaser. The Company also has oil price risk exposure related to synfuel tax credits. See discussion in Note 23E.

The Company uses natural gas hedging instruments to manage a portion of the market risk associated with fluctuations in the future sales price of the Company's natural gas. In addition, the Company may engage in limited economic hedging activity using natural gas and electricity financial instruments.

In 2004, PEF entered into derivative instruments related to its exposure to price fluctuations on fuel oil purchases. At December 31, 2004, the fair values of these 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. These instruments receive regulatory accounting treatment. Gains are recorded in regulatory liabilities and losses are recorded in regulatory assets.

Refer to Note 18 for additional information with regard to the Company's commodity contracts and use of derivative financial instruments.

The Company performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% increase or decrease in quoted market prices in the near term on the Company's derivative commodity instruments would not have had a material effect on the Company's consolidated financial position, results of operations or cash flows as of December 31, 2004.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

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 "Management's Discussion and Analysis of Financial Condition and Results of Operations" 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 2007 and future financing plans; c) "Strategy" about Progress Energy, Inc.'s, strategy; and d) "Other Matters" about the effects of new environmental regulations, nuclear decommissioning costs 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 Progress Energy, Inc., (the Company) does not undertake any 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 government laws and regulations, including those relating to the environment; deregulation or restructuring in the electric industry that may result in increased competition and unrecovered (stranded) costs; the ability of the Company to implement its cost-management initiatives as planned; the uncertainty regarding the timing, creation and structure of regional transmission organizations; weather conditions that directly influence the demand for electricity; the Company's ability to recover through the regulatory process, and the timing of such recovery of, the costs associated with the four hurricanes that impacted our service territory in 2004 or other 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 the Company and its subsidiaries' commercial and industrial customers; the ability of the Company's subsidiaries to pay upstream dividends or distributions to it; the impact on the facilities and the businesses of the Company from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the ability to successfully access capital markets on favorable terms; the impact on the Company's financial condition and ability to meet its cash and other financial obligations in the event its credit ratings are downgraded below investment grade; the impact that increases in leverage may have on the Company; the ability of the Company to maintain its current credit ratings; the impact of derivative contracts used in the normal course of business by the Company; investment performance of pension and benefit plans; the Company's ability to control costs, including pension and benefit expense, and achieve its cost-management targets for 2007; the availability and use of Internal Revenue Code Section 29 (Section 29) tax credits by synthetic fuel producers and the Company's continued ability to use Section 29 tax credits related to its coal and synthetic fuel businesses; the impact to the Company's financial condition and performance in the event it is determined the Company is not entitled to previously taken Section 29 tax credits; the impact of future accounting pronouncements regarding uncertain tax positions; the outcome of PEF's rate proceeding in 2005 regarding its future base rates; the Company's ability to manage the risks involved with the operation of its nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history; the Company's ability to manage the risks associated with its energy marketing operations; 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 the Company's subsidiaries.

These and other risk factors are detailed from time to time in the Company's 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 the control of Progress Energy. 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.

MANAGEMENT'S REPORT OF INTERNAL CONTROLS OVER FINANCIAL REPORTING

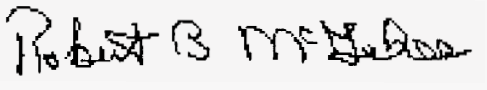
It is the responsibility of Progress Energy's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15(d)-15(f) of the Securities Exchange Act of 1934, as amended. Progress Energy's internal control over financial reporting 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 includes 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.

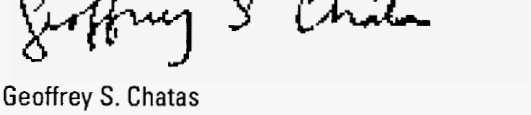
Management assessed the effectiveness of Progress Energy's internal control over financial reporting as of December 31, 2004. Management based this assessment on criteria for effective internal control over financial reporting described in *Internal Control – Integrated Framework* issued by the Committee 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, as of December 31, 2004, Progress Energy maintained effective internal control over financial reporting.

Management's assessment of the effectiveness of Progress Energy's internal control over financial reporting as of December 31, 2004, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.



Robert B. McGehee
Chairman and Chief Executive Officer



Geoffrey S. Chatas
Executive Vice President and Chief Financial Officer

March 7, 2005

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 as of December 31, 2004, 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 as of December 31, 2004, 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 as of December 31, 2004, 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, 2004, of the Company, and our report dated March 7, 2005, expressed an unqualified opinion on those consolidated financial statements.

Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2005

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, 2004 and 2003, 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, 2004. 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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1D and 18A to the consolidated financial statements, 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 as of December 31, 2004, 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 7, 2005, 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 7, 2005

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data) Years ended December 31	2004	2003	2002
Operating Revenues			
Electric	**$7,153**	$6,741	$6,601
Diversified business	**2,619**	2,000	1,490
Total Operating Revenues	**9,772**	8,741	8,091
Operating Expenses			
Utility			
Fuel used in electric generation	**2,011**	1,695	1,586
Purchased power	**868**	862	862
Operation and maintenance	**1,475**	1,421	1,390
Depreciation and amortization	**878**	883	820
Taxes other than on income	**425**	405	386
Diversified business			
Cost of sales	**2,288**	1,748	1,410
Depreciation and amortization	**190**	157	118
Impairment of long-lived assets	**–**	17	364
(Gain)/loss on the sale of assets	**(57)**	1	–
Other	**218**	195	145
Total Operating Expenses	**8,296**	7,384	7,081
Operating Income	**1,476**	1,357	1,010
Other Income (Expense)			
Interest income	**14**	11	15
Impairment of investments	**–**	(21)	(25)
Other, net	**8**	(16)	27
Total Other Income (Expense)	**22**	(26)	17
Interest Charges			
Net interest charges	**653**	635	641
Allowance for borrowed funds used during construction	**(6)**	(7)	(8)
Total Interest Charges, Net	**647**	628	633
Income from Continuing Operations before Income Tax, Minority Interest, and Cumulative Effect of Changes in Accounting Principles	**851**	703	394
Income Tax Expense (Benefit)	**115**	(111)	(158)
Income from Continuing Operations before Minority Interest and Cumulative Effect of Changes in Accounting Principles	**736**	814	552
Minority Interest, Net of Tax	**(17)**	3	–
Income from Continuing Operations Before Cumulative Effect of Changes in Accounting Principles	**753**	811	552
Discontinued Operations, Net of Tax	**6**	(8)	(24)
Cumulative Effect of Changes in Accounting Principles, Net of Tax	**–**	(21)	–
Net Income	**$759**	$782	$528
Average Common Shares Outstanding	**242**	237	217
Basic Earnings per Common Share			
Income from continuing operations before cumulative effect of changes in accounting principles	**$3.11**	$3.42	$2.54
Discontinued operations, net of tax	**.02**	(.03)	(.11)
Cumulative effect of changes in accounting principles, net of tax	**–**	(.09)	–
Net Income	**$3.13**	$3.30	$2.43
Diluted Earnings per Common Share			
Income from continuing operations before cumulative effect of changes in accounting principles	**$3.10**	$3.40	$2.53
Discontinued operations, net of tax	**.02**	(.03)	(.11)
Cumulative effect of changes in accounting principles, net of tax	**–**	(.09)	–
Net Income	**$3.12**	$3.28	$2.42
Dividends Declared per Common Share	**$2.32**	$2.26	$2.20

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2004	2003
ASSETS		
Utility Plant		
Utility plant in service	**$22,103**	$21,680
Accumulated depreciation	**(8,783)**	(8,174)
Utility plant in service, net	**13,320**	13,506
Held for future use	**13**	13
Construction work in progress	**799**	559
Nuclear fuel, net of amortization	**231**	228
Total Utility Plant, Net	**14,363**	14,306
Current Assets		
Cash and cash equivalents	**62**	47
Short-term investments	**82**	226
Receivables	**1,084**	1,084
Inventory	**982**	907
Deferred fuel cost	**229**	270
Deferred income taxes	**121**	87
Prepayments and other current assets	**175**	268
Total Current Assets	**2,735**	2,889
Deferred Debits and Other Assets		
Regulatory assets	**1,064**	598
Nuclear decommissioning trust funds	**1,044**	938
Diversified business property, net	**2,010**	2,095
Miscellaneous other property and investments	**446**	464
Goodwill	**3,719**	3,726
Prepaid pension costs	**42**	462
Intangibles, net	**337**	357
Other assets and deferred debits	**233**	258
Total Deferred Debits and Other Assets	**8,895**	8,898
Total Assets	**$25,993**	$26,093

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2004	2003
CAPITALIZATION AND LIABILITIES		
Common Stock Equity		
Common stock without par value, 500 million shares authorized, 247 million and 246 million shares issued and outstanding, respectively	$5,360	$5,270
Unearned restricted shares (1 million and 1 million shares, respectively)	(13)	(17)
Unearned ESOP shares (3 million and 4 million shares, respectively)	(76)	(89)
Accumulated other comprehensive loss	(164)	(50)
Retained earnings	2,526	2,330
Total Common Stock Equity	7,633	7,444
Preferred Stock of Subsidiaries – Not Subject to Mandatory Redemption	93	93
Minority Interest	36	30
Long-Term Debt, Affiliate	270	270
Long-Term Debt, Net	9,251	9,664
Total Capitalization	17,283	17,501
Current Liabilities		
Current portion of long-term debt	349	868
Accounts payable	742	635
Interest accrued	219	228
Dividends declared	145	140
Short-term obligations	684	4
Customer deposits	180	167
Other current liabilities	742	608
Total Current Liabilities	3,061	2,650
Deferred Credits and Other Liabilities		
Noncurrent income tax liabilities	599	701
Accumulated deferred investment tax credits	176	190
Regulatory liabilities	2,654	2,879
Asset retirement obligations	1,282	1,271
Accrued pension and other benefits	562	508
Other liabilities and deferred credits	376	393
Total Deferred Credits and Other Liabilities	5,649	5,942
Commitments and Contingencies (Notes 22 and 23)		
Total Capitalization and Liabilities	$25,993	$26,093

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	2004	2003	2002
Operating Activities			
Net income	$759	$782	$528
Adjustments to reconcile net income to net cash provided by operating activities			
(Income) loss from discontinued operations	(6)	8	24
Net (gain) loss on sale of operating assets	(57)	1	–
Impairment of long-lived assets and investments	–	38	389
Cumulative effect of changes in accounting principles	–	21	–
Depreciation and amortization	1,181	1,146	1,099
Deferred income taxes	(74)	(276)	(402)
Investment tax credit	(14)	(16)	(18)
Deferred fuel credit	(19)	(133)	(37)
Cash provided (used) by changes in operating assets and liabilities			
Receivables	(35)	(158)	(50)
Inventory	(108)	8	(66)
Prepayments and other current assets	(18)	39	(24)
Accounts payable	33	37	100
Other current liabilities	82	121	56
Regulatory assets and liabilities	(284)	(21)	46
Other	167	127	(18)
Net Cash Provided by Operating Activities	1,607	1,724	1,627
Investing Activities			
Gross utility property additions	(998)	(972)	(1,169)
Diversified business property additions	(236)	(584)	(558)
Nuclear fuel additions	(101)	(117)	(81)
Proceeds from sales of subsidiaries and other investments	366	579	43
Acquisition of businesses, net of cash	–	–	(365)
Purchases of short-term investments	(2,108)	(2,813)	(2,962)
Proceeds from sales of short-term investments	2,252	2,587	2,962
Acquisition of intangibles	(1)	(200)	(10)
Other	(46)	(26)	(61)
Net Cash Used in Investing Activities	(872)	(1,546)	(2,201)
Financing Activities			
Issuance of common stock, net	73	304	687
Issuance of long-term debt, net	421	1,539	1,783
Net increase (decrease) in short-term indebtedness	680	(696)	(247)
Retirement of long-term debt	(1,353)	(810)	(1,157)
Dividends paid on common stock	(558)	(541)	(480)
Other	17	12	(5)
Net Cash (Used in) Provided by Financing Activities	(720)	(192)	581
Net Increase (Decrease) in Cash and Cash Equivalents	15	(14)	7
Cash and Cash Equivalents at Beginning of Year	47	61	54
Cash and Cash Equivalents at End of Year	$62	$47	$61
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year – interest (net of amount capitalized)	$657	$643	$651
– income taxes (net of refunds)	$189	$177	$219

Noncash Activities

- In April 2002, Progress Fuels Corporation, a subsidiary of the Company, acquired 100% of Westchester Gas Company. In conjunction with the purchase, the Company issued approximately $129 million in common stock (See Note 5D).
- In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc., both indirectly wholly owned subsidiaries of Progress Energy, and EPIK Communications, Inc., a wholly owned subsidiary of Odyssey Telecorp, Inc., contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC, a subsidiary of PTC (See Note 5A).

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 Income (Loss)	Retained Earnings	Total Common Stock Equity
Balance, January 1, 2002	219	$4,121	$(14)	$(114)	$(32)	$2,043	$6,004
Net income						528	528
Other comprehensive loss					(206)		(206)
Issuance of shares	19	815					815
Purchase of restricted stock			(16)				(16)
Restricted stock expense recognition			8				8
Cancellation of restricted shares		(1)	1				–
Allocation of ESOP shares		16		12			28
Dividends ($2.20 per share)						(484)	(484)
Balance, December 31, 2002	238	4,951	(21)	(102)	(238)	2,087	6,677
Net income						782	782
Other comprehensive income					188		188
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)**
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**

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2004**	2003	2002
Net Income	**$759**	$782	$528
Other Comprehensive Income (Loss)			
Changes in net unrealized losses on cash flow hedges (net of tax benefit of $10, $7 and $18, respectively)	**(18)**	(12)	(28)
Reclassification adjustment for amounts included in net income (net of tax expense of ($16), ($11) and ($10), respectively)	**26**	19	16
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 $78, ($112) and $121, respectively)	**(130)**	177	(192)
Foreign currency translation and other	**4**	4	(2)
Other Comprehensive Income (Loss)	**$(114)**	$188	$(206)
Comprehensive Income	**$645**	$970	$322

See Notes to Consolidated Financial Statements.

ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Progress Energy, Inc. (Progress Energy or the Company) is a holding company headquartered in Raleigh, North Carolina. The Company is registered under the Public Utility Holding Company Act of 1935 (PUHCA), as amended, and as such, the Company and its subsidiaries are subject to the regulatory provisions of PUHCA. Effective January 1, 2003, three of the Company's subsidiaries, Carolina Power & Light Company (CP&L), Florida Power Corporation and Progress Ventures, Inc., began doing business under the assumed names Progress Energy Carolinas, Inc. (PEC), Progress Energy Florida, Inc. (PEF) and Progress Energy Ventures, Inc. (PVI), respectively.

Through its wholly owned subsidiaries, PEC and PEF, the Company's PEC Electric and PEF segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. The Progress Ventures business unit consists of the Fuels business segment (Fuels) and Competitive Commercial Operations (CCO) operating segments. The Fuels segment is involved in natural gas drilling and production, coal terminal services, coal mining, synthetic fuel production, fuel transportation and delivery. The CCO segment includes nonregulated generation and energy marketing activities. Through the Rail Services (Rail) segment, the Company is involved in nonregulated railcar repair, rail parts reconditioning and sales and scrap metal recycling. Through its other business units, the Company engages in other nonregulated business areas, including telecommunications and energy management and related services. Progress Energy's legal structure is not currently aligned with the functional management and financial reporting of the Progress Ventures business unit. Whether, and when, the legal and functional structures will converge depends upon legislative and regulatory action, which cannot currently be anticipated.

B. Basis of Presentation

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the activities of the Company and its majority-owned subsidiaries. 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," 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.

The consolidated financial statements of the Company and its subsidiaries include the majority-owned and controlled subsidiaries. Noncontrolling interests in the 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 the Company does not have control, but has the ability to exercise influence over operating and financial policies (generally 20%–50% 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). These equity method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the Company has equity method investments of approximately $27 million and $36 million, respectively.

Certain investments in debt and equity securities that have readily determinable market values, and for which the Company does not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." These investments include investments held in trust funds, pursuant to the United States Nuclear Regulatory Commission (NRC) requirements, to fund certain costs of decommissioning nuclear plants. The fair value of these trust funds was $1.044 billion and $938 million at December 31, 2004 and 2003, respectively. The Company also 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 the Company intends to sell these instruments generally within 30 days from the balance sheet date, they are classified as current assets. At December 31, 2004 and 2003, the fair value of these investments was $82 million

and $226 million, respectively. Other investments in debt and equity securities are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the fair value of these other investments was $39 million and $39 million, respectively.

Other investments are stated principally at cost. These cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004, and 2003, the Company has approximately $14 million and $14 million, respectively, of cost method investments.

The results of operations of Rail are reported one month in arrears. During 2003, the Company ceased recording portions of the Fuels' segment operations one month in arrears. The net impact of this action increased net income by $2 million for the year.

Certain amounts for 2003 and 2002 have been reclassified to conform to the 2004 presentation. Reclassifications include the reclassification of instruments used in PEC's cash management program from cash and cash equivalents to short-term investments of $226 million at December 31, 2003, in the Consolidated Balance Sheets. In the Consolidated Statements of Cash Flow for each of the three years in the period ended December 31, 2004, total cash balances and total cash flows used in investing activities were revised to reflect the reclassification of these instruments from cash and cash equivalents to short-term investments.

Consolidation of Variable Interest Entities

The Company consolidates all voting interest entities in which it owns a majority voting interest and all variable interest entities for which it is the primary beneficiary in accordance with **FASB** Interpretation No. 46R, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51" (FIN No. 46R). The Company 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 Internal Revenue Code (Code). As of December 31, 2004, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in other current assets and miscellaneous other property and investments in the Consolidated Balance Sheets.

The Company is the primary beneficiary of a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The Company has requested but has not received all the necessary information to determine the primary beneficiary of the limited partnership's underlying 17 partnership investments, and has applied the information scope exception in FIN No. 46R, paragraph 4(g) to the 17 partnerships. The Company has no direct exposure to loss from the 17 partnerships; the Company's only exposure to loss is from its investment of less than $1 million in the consolidated limited partnership. The Company will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to the 17 partnerships. The Company believes 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 the Company's Consolidated Balance Sheets.

The Company has variable interests in two power plants resulting from long-term power purchase contracts. The Company has requested the necessary information to determine if the counterparties are variable interest entities or to identify the primary beneficiaries. Both entities declined to provide the Company with the necessary financial information, and the Company has applied the information scope exception in FIN No. 46R, paragraph 4(g). The Company's only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the two entities' plants to produce the power purchased by the Company. The Company is able to recover these fuel costs under PEC's fuel clause. Total purchases from these counterparties were approximately $58 million, $53 million and $53 million in 2004, 2003 and 2002, respectively. The Company will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to these contracts. The combined generation capacity of the two entities' power plants is approximately 880 MW. The Company believes that if it is determined to be the primary beneficiary of these two entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on the Company's common stock equity, net earnings or cash flows. However, because the Company has not received any financial information from these two counterparties, the impact cannot be determined at this time.

The Company also has interests in several other variable interest entities for which the Company is not the primary beneficiary. These arrangements include investments in approximately 28 limited partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities.

The aggregate maximum loss exposure at December 31, 2004, that the Company could be required to record in its income statement as a result of these arrangements totals approximately $38 million. The creditors of these variable interest entities do not have recourse to the general credit of the Company in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

In preparing consolidated financial statements that conform with 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.

REVENUE RECOGNITION

The Company recognizes 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.

FUEL COST DEFERRALS

Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by the electric 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.

EXCISE TAXES

PEC and PEF collect from customers certain excise taxes levied by the state or local government upon the customers. PEC and PEF account for excise taxes on a gross basis. For the years ended December 31, 2004, 2003 and 2002, gross receipts tax, franchise taxes and other excise taxes of approximately $240 million, $217 million and $212 million, respectively, are included in utility revenues and taxes other than on income in the Consolidated Statements of Income.

STOCK-BASED COMPENSATION

The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at the grant date, and accordingly, no compensation expense has been recognized for stock option grants. For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – An Amendment of FASB Statement No. 123" (SFAS No. 148), the estimated fair value of the Company's stock options is amortized to expense over the options' vesting period. The following table illustrates the effect on net income and earnings per share if the fair value method had been applied to all outstanding and unvested awards in each period:

(in millions except per share data)	**2004**	2003	2002
Net income, as reported	**$759**	$782	$528
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**10**	11	8
Pro forma net income	**$749**	$771	$520
Earnings per share			
Basic – as reported	**$3.13**	$3.30	$2.43
Basic – pro forma	**$3.09**	$3.25	$2.40
Diluted – as reported	**$3.12**	$3.28	$2.42
Diluted – pro forma	**$3.08**	$3.24	$2.39

See Note 2 for a discussion of newly issued accounting guidance related to stock-based compensation.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. The Company capitalizes 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 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, the Company adopted the guidance in SFAS No. 143 to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present value of retirement costs for which the Company has 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.

The adoption of this statement had no impact on the income of the regulated entities, as the effects were offset by the establishment of a regulatory asset and a regulatory liability pursuant to SFAS No. 71 (See Note 8A). The North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (SCPSC) and the Florida Public Service Commission (FPSC) issued orders to authorize deferral of all prospective effects related to SFAS No. 143 as a regulatory asset or liability (See Note 8A). Therefore, SFAS No. 143 has no impact on the income of the regulated entities.

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 6A). 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 8).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In the Company's 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 Federal Energy Regulatory Commission (FERC).

CASH AND CASH EQUIVALENTS

The Company considers 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

The Company accounts for inventory using the average-cost method. Inventories are valued at the lower of average cost or market.

REGULATORY ASSETS AND LIABILITIES

The Company's regulated 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 Company records 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 8A).

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 6B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

The Company uses the full-cost method to account for its 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 the Company's 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.

UNAMORTIZED 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 life using the straight-line method consistent with ratemaking treatment (See Note 8A).

INCOME TAXES

The Company and its 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 AMT 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.

DERIVATIVES

The Company accounts 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 and 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. The Company generally designates 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, the Company 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.

ENVIRONMENTAL

As discussed in Note 22, the Company accrues environmental remediation liabilities when the criteria for SFAS No. 5, "Accounting for Contingencies" (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 the Company's asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

As discussed in Note 10, the Company reviews 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. The accounting for impairment of assets is based on SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

The Company reviews its investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. The Company considers 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 the Company determines that an other-than-temporary decline exists in the value of its investments, it is the Company's 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, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2004, 2003 or 2002.

SUBSIDIARY STOCK TRANSACTIONS

Gains and losses realized as a result of common stock sales by the Company's 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

FASB STAFF POSITION 106-2, "ACCOUNTING AND DISCLOSURE REQUIREMENTS RELATED TO THE MEDICARE PRESCRIPTION DRUG IMPROVEMENT AND MODERNIZATION ACT OF 2003"

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) was signed into law. In accordance with guidance issued by the Financial Accounting Standards Board (FASB) in FASB Staff Position 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003" (FASB Staff Position 106-1), the Company elected to defer accounting for the effects of the Medicare Act due to uncertainties regarding the effects of the implementation of the Medicare Act and the accounting for certain provisions of the Medicare Act. In May 2004, the FASB issued definitive accounting guidance for the Medicare Act in FASB Staff Position 106-2, which was effective for the Company in the third quarter of 2004. FASB Staff Position 106-2 results in the recognition of lower other postretirement employment benefit (OPEB) costs to reflect prescription drug-related federal subsidies to be received under the Medicare Act. As a result of the Medicare Act, the Company's accumulated postretirement benefit obligation as of January 1, 2004, was reduced by approximately $83 million, and the Company's 2004 net periodic cost was reduced by approximately $13 million.

SFAS NO. 123 (REVISED 2004), "SHARE-BASED PAYMENT" (SFAS NO. 123R)

In December 2004, the FASB issued SFAS No. 123R, which revises SFAS No. 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." The key requirement of SFAS No. 123R is that the cost of share-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. Previously, entities could elect to continue accounting for such awards at their grant date intrinsic value under APB Opinion No. 25, and the Company made that election. The intrinsic value method resulted in the Company recording no compensation expense for stock options granted to employees (See Note 11).

SFAS No. 123R will be effective for the Company on July 1, 2005. The Company intends to implement the standard using the required modified prospective method. Under that method, the Company will record

compensation expense under SFAS No. 123R for all awards it grants after July 1, 2005, and it will record compensation expense (as previous awards continue to vest) for the unvested portion of previously granted awards that remain outstanding at July 1, 2005. In 2004, the Company made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued. The Company expects to record approximately $3 million of pre-tax expense for stock options in 2005.

PROPOSED FASB INTERPRETATION OF SFAS NO. 109, "ACCOUNTING FOR INCOME TAXES"

In July 2004, the FASB stated that it plans to issue 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 FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the consolidated financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits (See Note 23E).

HURRICANE-RELATED COSTS

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of the Company's service territories during the third quarter of 2004, significantly impacting PEF's territory. As of December 31, 2004, restoration of the Company's systems from hurricane-related damage was estimated at $398 million. PEC incurred restoration costs of $13 million, of which $12 million was charged to operation and maintenance expense and $1 million was charged to capital expenditures. PEF had estimated total costs of $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions. As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Storm reserve costs of $13 million were attributable to wholesale customers. The Company has received approval from the FERC to amortize these costs consistent with recovery of such amounts in wholesale rates. PEF continues to review the restoration cost invoices received. Given that not all invoices have been received as of December 31, 2004, PEF will update its petition with the FPSC upon receipt and audit of all actual charges incurred. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005.

On November 17, 2004, the Citizens of the State of Florida, by and through Harold McLean, Public Counsel, and the Florida Industrial Power Users Group (FIPUG), (collectively, Joint Movants), filed a Motion to Dismiss PEF's petition to recover the $252 million in storm costs. On November 24, 2004, PEF responded in opposition to the motion, which was also the FPSC staff's position in its recommendation to the Commission on December 21, 2004, that it should deny the Motion to Dismiss. On January 4, 2005, the Commission ruled in favor of PEF and denied Joint Movant's Motion to Dismiss.

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period (See Note 8C).

PEC does not have an ongoing regulatory mechanism to recover storm costs; therefore, hurricane restoration costs recorded in the third quarter of 2004 were charged to operations and maintenance expenses or capital expenditures based on the nature of the work performed. In connection with other storms, PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over a five-year period. PEC did not seek deferral of 2004 storm costs from the NCUC (See Note 8B).

4. DIVESTITURES

A. Sale of Natural Gas Assets

In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd. (Winchester Production), an indirectly wholly owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Fuels 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 the Company's 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.

B. Divestiture of Synthetic Fuel Partnership Interests

In June 2004, the Company through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 Company's book value of the interests sold totaled approximately $5 million. The Company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007, and approximately $8 million through the second quarter of 2008. 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.

C. Railcar Ltd., Divestiture

In December 2002, the Progress Energy Board of Directors adopted a resolution approving the sale of Railcar Ltd., a subsidiary included in the Rail Services segment. An estimated pre-tax impairment of $59 million on assets held for sale was recognized in December 2002 to write-down the assets to fair value less costs to sell. This impairment has been included in impairment of long-lived assets in the Consolidated Statements of Income (See Note 10A). In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc., and the transaction closed in February 2004. Proceeds from the sale were approximately $82 million before transaction costs and taxes of approximately $13 million. In July 2004, the Company sold the remaining assets classified as held for sale to a third-party for net proceeds of $6 million. The assets of Railcar Ltd. were grouped as assets held for sale and were included in other current assets on the Consolidated Balance Sheets at December 31, 2003, at approximately $75 million, which reflected the Company's estimates of the fair value expected to be realized from the sale of these assets less costs to sell.

D. Mesa Hydrocarbons, Inc., Divestiture

In October 2003, the Company sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels. Net proceeds were approximately $97 million. Because the Company utilizes the full-cost method of accounting for its oil and gas operations, the pre-tax gain of approximately $18 million was applied to reduce the basis of the Company's 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.

E. NCNG Divestiture

On September 30, 2003, the Company completed the sale of North Carolina Natural Gas Corporation (NCNG) and the Company's 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 and $16 million for the years ended December 31, 2003 and 2002, respectively, has been allocated to discontinued operations based on the net assets of NCNG, assuming a uniform debt-to-equity ratio across the Company's operations. The Company ceased recording depreciation effective October 1, 2002, upon classification of the assets as discontinued operations. After-tax depreciation expense recorded by NCNG for the year ended December 31, 2002, was $9 million. Results of discontinued operations for years ended December 31 were as follows:

(in millions)	2004	2003	2002
Revenues	$–	$284	$300
Earnings before income taxes	$–	$6	$9
Income tax expense	–	2	4
Net earnings from discontinued operations	–	4	5
Gain/(Loss) on disposal of discontinued operations, including applicable income tax benefit/(expense) of $6, $1 and $3, respectively	6	(12)	(29)
Earnings (loss) from discontinued operations	$6	$(8)	$(24)

During 2004, the Company 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.

7 ACQUISITIONS AND BUSINESS COMBINATIONS

A. Progress Telecommunications Corporation

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. 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 holds a 55% ownership interest in, and is the parent of, PT LLC. Odyssey holds a combined 45% ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Company's 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 certain leasing arrangements of EPIK and finalized its valuation of acquired assets and liabilities. Management considered a number of factors, including valuations and appraisals, when making these determinations. Based on the results of these activities, the preliminary purchase price allocation for EPIK was revised as follows at December 31, 2004: property and equipment – $36 million; other current assets – $7 million; intangible assets – $1 million; current liabilities – $18 million; and exit costs – $4 million. The exit costs consist primarily of lease termination penalties and noncancelable lease payments made after certain leased properties are vacated. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2003 or 2002.

B. Acquisition of Natural Gas Reserves

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (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 years ended December 31, 2003 and 2002.

C. Wholesale Energy Contract Acquisition

In May 2003, 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 calls for 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 9). The power supply agreement terminates in 2015, with a first refusal right to extend for five years. The agreement includes the use of 640 megawatts (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.

D. Westchester Acquisition

In April 2002, Progress Fuels, a subsidiary of Progress Energy, acquired 100% of Westchester Gas Company (Westchester). During 2004 the name of the company was changed to Winchester Energy Co. Ltd. The acquisition included approximately 215 natural gas-producing wells, 52 miles of intrastate gas pipeline and 170 miles of gas-gathering systems located within a 25-mile radius of Jonesville, Texas, on the Texas-Louisiana border.

The aggregate purchase price of approximately $153 million consisted of cash consideration of approximately $22 million and the issuance of 2.5 million shares of Progress Energy common stock then valued at approximately $129 million. The purchase price included approximately $2 million of direct transaction costs. The final purchase price was allocated to oil and gas properties, intangible assets, diversified business property, net working capital and deferred tax liabilities for approximately $152 million, $9 million, $32 million, $5 million and $45 million, respectively. The $9 million intangible assets relates to customer contracts (See Note 9).

The acquisition has been accounted for using the purchase method of accounting and, accordingly, the results of operations for Westchester have been included in Progress Energy's Consolidated Financial Statements since the date of acquisition. 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, 2002.

E. Generation Acquisition

In February 2002, PVI acquired 100% of two electric generating projects located in Georgia from LG&E Energy Corp., a subsidiary of Powergen plc. The two projects consist of 1) Walton County Power, LLC, in Monroe, Georgia, a 460 MW natural gas-fired plant placed in service in June 2001 and 2) Washington County Power, LLC, in Washington County, Georgia, a 600 MW natural gas-fired plant placed in service in June 2003. The Walton and Washington projects have been accounted for using the purchase method of accounting and, accordingly, have been included in the Consolidated Financial Statements since the acquisition date.

In the final allocation, the aggregate cash purchase price of approximately $348 million was allocated to diversified business property, intangibles and goodwill for $228 million, $56 million and $64 million, respectively (See Note 9). Of the acquired intangible assets, $33 million was assigned to tolling and power sale agreements with LG&E Energy Marketing, Inc., for each project and $23 million was assigned to interconnection contracts. Goodwill was assigned to the CCO segment and will be deductible for tax purposes.

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, 2002.

PROPERTY, PLANT AND EQUIPMENT

Utility Plant

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

(in millions)	**2004**	2003
Production plant (7-33 years)	**$11,966**	$12,044
Transmission plant (30-75 years)	**2,282**	2,167
Distribution plant (12-50 years)	**6,749**	6,432
General plant and other (8-75 years)	**1,106**	1,037
Utility plant in service	**$22,103**	$21,680

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.

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. The composite AFUDC rate for PEC's electric utility plant was 7.2% in 2004, 4.0% in 2003 and 6.2% in 2002, respectively. The composite AFUDC rate for PEF's electric utility plant was 7.8% in 2004, 2003 and 2002.

Depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.2%, 2.5% and 2.6% in 2004, 2003 and 2002, respectively. The depreciation provisions related to utility plant were $463 million, $517 million and $488 million in 2004, 2003 and 2002, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, asset retirement obligation (ARO) accretion, cost of removal

provisions (See Note 6D), regulatory approved expenses (See Note 8 and Note 22) and NC Clean Air Legislation amortization (See Note 8B).

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 new depreciation rates were effective January 1, 2004.

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, 2004, 2003 and 2002 were $140 million, $143 million and $141 million, respectively, and are included in fuel used for electric generation in the Consolidated Statements of Income.

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)	**2004**	2003
Equipment (3-25 years)	**$383**	$246
Nonregulated generation plant and equipment (3-40 years)	**1,302**	1,299
Land and mineral rights	**107**	93
Buildings and plants (5-40 years)	**131**	125
Oil and gas properties (units-of-production)	**336**	412
Telecommunications equipment (5-20 years)	**80**	63
Rail equipment (3-20 years)	**29**	125
Marine equipment (3-35 years)	**87**	83
Computers, office equipment and software (3-10 years)	**36**	36
Construction work in progress	**26**	13
Accumulated depreciation	**(507)**	(400)
Diversified business property, net	**$2,010**	$ 2,095

The synthetic fuel facilities are being depreciated through 2007 when the Section 29 tax credits will expire. The Company's nonregulated businesses capitalize interest costs under SFAS No. 34, "Capitalization of Interest Costs." During the years ended December 31, 2004, 2003 and 2002, respectively, the Company capitalized $7 million, $20 million and $38 million, respectively, of its interest cost of $660 million, $655 million and $679 million. Capitalized interest for 2004 is related to the expansion of Fuels' gas operations. Capitalized interest in 2003 and 2002 is related to the expansion of its nonregulated generation portfolio at PVI. Capitalized interest is included in diversified business property, net on the Consolidated Balance Sheets. Diversified business depreciation expense was $148 million, $120 million and $85 million for December 31, 2004, 2003 and 2002, respectively.

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. 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 on the following table with related information at December 31 ($ in millions):

2004 Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	**Mayo Plant**	**83.83%**	**$516**	**$249**	**$1**
PEC	**Harris Plant**	**83.83%**	**3,185**	**1,387**	**13**
PEC	**Brunswick Plant**	**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**

2003 Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo Plant	83.83%	$464	$242	$50
PEC	Harris Plant	83.83%	3,248	1,424	7
PEC	Brunswick Plant	81.67%	1,611	885	21
PEC	Roxboro Unit 4	87.06%	323	139	1
PEF	Crystal River Unit 3	91.78%	875	442	46
PEF	Intercession City Unit P11	66.67%	22	6	6

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris Plant).

Asset Retirement Obligations

At December 31, 2004 and 2003, the asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $277 million and $354 million, respectively. Funds set aside in the Company's nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $1.044 billion and $938 million at December 31, 2004 and 2003, respectively. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 8A).

Decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million in each of 2004, 2003 and 2002. 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. The Company's expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset removal obligations, which are included in depreciation and amortization expense, were $160 million, $158 million and $149 million in 2004, 2003 and 2002, respectively.

The utilities recognize removal, nonirradiated decommissioning and dismantlement costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 8A). At December 31, 2004, such costs consist of removal costs of $1.606 billion, removal costs for nonirradiated areas at nuclear facilities of $131 million and amounts previously collected for dismantlement of fossil generation plants of $144 million. At December 31, 2003, such costs consist of removal costs of $1.846 billion, removal costs for nonirradiated areas at nuclear facilities of $129 million and amounts previously collected for dismantlement of fossil generation plants of $143 million. During 2004, PEC reduced its estimated removal costs to take into account the estimates used in the depreciation studies implemented during 2004 (See Note 6A). This resulted in a downward revision in the PEC estimated removal costs and equal increase in accumulated depreciation of approximately $345 million.

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 estimates, in 2004 dollars, are $294 million for Robinson Unit No. 2, $290 million for Brunswick Unit No. 1, $313 million for Brunswick Unit No. 2 and $359 million for the Harris Plant. 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 the Brunswick and Harris nuclear generating facilities. NRC operating licenses held by PEC currently expire in December 2014 and September 2016 for Brunswick Units 2 and 1, respectively. An application to extend these licenses 20 years was submitted in October 2004. The NRC operating license held by PEC for the Harris Plant 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 has renewed the operating license for PEC's Robinson Nuclear Plant (Robinson) for an additional 20 years through July 2030.

PEF's most recent site-specific estimate of decommissioning costs for the Crystal River Nuclear Unit 3 (CR3) was developed in 2000 based on prompt dismantlement decommissioning. The estimate, in 2000 dollars, is $491 million and is subject to change based on the same factors as discussed above for PEC's estimates. 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.

The Company has identified but not recognized AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by the Company. 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 the Company intends to utilize these properties indefinitely. In the event the Company decides to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

The Company's nonregulated AROs relate to coal mine operations, synthetic fuel operations and gas production of Progress Fuels. The related asset retirement costs, net of accumulated depreciation, totaled $10 million and $5 million at December 31, 2004 and 2003, respectively.

The following table shows the changes to the asset retirement obligations. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels. The deductions to regulated ARO related to PEC re-measuring 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.

(in millions)	Regulated	Nonregulated
Asset retirement obligations as of January 1, 2003	$1,183	$10
Additions	–	11
Accretion expense	68	1
Deductions	–	(2)
Asset retirement obligations as of December 31, 2003	1,251	20
Additions	–	6
Accretion expense	73	2
Deductions	(63)	(7)
Asset retirement obligations as of December 31, 2004	$1,261	$21

The cumulative effect of initial adoption of this statement 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. Pro forma net income has not been presented for prior years because the pro forma application of SFAS No. 143 to prior years would result in pro forma net income not materially different from the actual amounts reported.

Insurance

PEC and PEF 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 $2.0 billion on the Brunswick and Harris plants, and $1.1 billion on the Robinson Plant and CR3.

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 million per week at the Brunswick and Harris plants, $2.5 million per week at the Robinson Plant and $4.5 million per week at CR3. An additional 110 weeks (71 weeks for CR3) of coverage is provided at 80% of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $29.3 million with respect to the primary coverage, $32.4 million with respect to the decontamination, decommissioning and excess property

coverage, and $20.2 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 PEC and PEF are insured against public liability for a nuclear incident up to $10.8 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 $101 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 $10 million per reactor owned. Congress could possibly approve revisions to the Price Anderson Act during 2005 that could include increased limits and assessments per reactor owned. The final outcome of this matter cannot be predicted at this time.

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 the terrorist acts.

PEC and PEF 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 Notes 3 and 8A).

CURRENT ASSETS

Receivables

At December 31, receivables were comprised of:

(in millions)	**2004**	2003
Trade accounts receivable	**$689**	$705
Unbilled accounts receivable	**271**	293
Notes receivable	**98**	61
Other receivables	**27**	47
Unbilled other receivables	**28**	10
Allowance for doubtful accounts receivable	**(29)**	(32)
Total receivables	**$1,084**	$1,084

Income tax receivables and interest income receivables are not included in this classification. These amounts are in prepaids and other current assets on the Consolidated Balance Sheet.

Inventory

At December 31, inventory was comprised of:

(in millions)	**2004**	2003
Fuel for production	**$235**	$210
Inventory for sale	**230**	167
Materials and supplies	**517**	530
Total inventory	**$982**	$907

REGULATORY MATTERS

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 applied to a separable portion of the Company's 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)	**2004**	2003
Deferred fuel cost – current (Note 8B and 8C)	**$229**	$270
Deferred fuel cost – long-term (Note 8B and 8C)	**107**	47
Deferred impact of ARO – PEC (Note 1D)	**305**	291
Income taxes recoverable through future rates (Note 15)	**84**	75
Loss on reacquired debt (Note 1D)	**53**	55
Deferred DOE enrichment facilities-related costs	**16**	24
Storm deferral (Notes 3 and 8B)	**316**	21
Postretirement benefits (Note 17)	**74**	9
Other	**109**	76
Total long-term regulatory assets	**$1,064**	$598
Deferred energy conservation cost – current	(8)	(7)
Non-ARO cost of removal (Note 6D)	**(1,881)**	(2,118)
Deferred impact of ARO (Note 1D)	**(221)**	(212)
Net nuclear decommissioning trust unrealized gains (Note 6D)	**(224)**	(204)
Postretirement benefits (Note 17B)	**(45)**	(211)
Storm reserve (Note 3)	**–**	(41)
Clean air compliance (Note 8B)	**(248)**	(74)
Other	**(35)**	(19)
Total long-term regulatory liabilities	**(2,654)**	(2,879)
Net regulatory liabilities	**$(1,369)**	$(2,018)

Except for portions of deferred fuel costs and deferred storm 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. The Company expects to fully recover these assets and refund the liabilities through customer rates under current regulatory practice.

PEC Retail Rate Matters

As of December 31, 2004, PEC's North Carolina retail fuel costs were underrecovered by $145 million. This amount is comprised of $117 million eligible for recovery in 2005 and $28 million deferred from a 2001 order from the NCUC that cannot be collected during 2005, and has therefore been classified as a long-term asset. PEC intends to collect this amount by October 31, 2007.

On October 15, 2004, the SCPSC approved PEC's request to leave fuel rates unchanged. The deferred fuel balance at December 31, 2004, is $23 million. This amount is eligible for recovery in PEC's 2005 South Carolina fuel review.

PEC obtained SCPSC and NCUC approval of fuel factors in annual fuel-adjustment proceedings. The NCUC approved an annual increase of $62 million, $20 million and $46 million by orders issued in September 2004, 2003 and 2002, respectively. The SCPSC approved PEC's petition each year and the changes were insignificant.

PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. 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.

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 ice storm and amortize them over a period of five years. PEC charged approximately $24 million in 2003 from Hurricane Isabel and from ice storms to the deferred account. PEC recognized $5 million and $3 million of NC storm amortization during 2004 and 2003, respectively.

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 2004 and 2003 and additional depreciation expense of approximately $53 million in 2002. Total accelerated depreciation recorded through December 31, 2004, was $403 million.

The North Carolina Clean Smokestacks Act enacted in June 2002 (NC Clean Air) requires state utilities to reduce emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from coal-fired plants. The NCUC has allowed the utilities to amortize and recover the costs 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 when setting the amortization amount for each year. PEC recognized $174 million and $74 million of clean air amortization during 2004 and 2003, respectively. This legislation freezes PEC's base rates in North Carolina for five years, subject to certain conditions (See Note 22).

In conjunction with the FPC merger, PEC reached a settlement with the Public Staff of the NCUC in which it agreed to provide credits to its nonreal time pricing customers in the amounts of $3 million in 2002, $5 million in 2003 and $6 million in both 2004 and 2005.

In conjunction with the acquisition of NCNG in 1999, PEC agreed not to seek a base retail electric rate increase in North Carolina and South Carolina through December 2004. The agreement not to seek a base retail electric rate increase in South Carolina was extended to December 2005 in conjunction with regulatory approval to form a holding company.

C. PEF Retail Rate Matters

On November 9, 2004, the FPSC approved PEF's underrecovered fuel costs of $156 million for 2004, of which PEF plans to defer $79 million until 2006 to mitigate the impact on customers resulting from the need to also recover hurricane-related costs. Therefore, $79 million of deferred fuel costs has been classified as a long-term asset. As of December 31, 2004, PEF was underrecovered in fuel costs by $168 million. The additional $12 million over and above the $156 million approved by the FPSC will be included in PEF's 2005 fuel filing.

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 the Company's affiliated coal supplier, Progress Fuels Corporation. 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 underruns. Any costs that exceed this estimate will not be recoverable absent extraordinary circumstances as found by the FPSC in subsequent proceedings.

See Note 3 for information on PEF's petition for storm cost recovery.

PEF RATE CASE SETTLEMENT

The FPSC initiated a rate proceeding in 2001 regarding PEF's future base rates. In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC in April 2002. The Agreement is generally effective from May 2002 through December 2005, provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates.

The Agreement provides that PEF will reduce its retail revenues from the sale of electricity by an annual amount of $125 million. The Agreement also provides that PEF will operate under a Revenue Sharing Incentive Plan (the Plan) through 2005, and thereafter until terminated by the FPSC, that establishes annual revenue caps and sharing thresholds. The Plan provides that retail base rate revenues between the sharing thresholds and the retail base rate revenue caps will be divided into two shares – a $1/3$ share to be received by PEF's shareholders, and a $2/3$ share to be refunded to PEF's retail customers, provided, however, that for the year 2002 only, the refund to customers was limited to 67.1% of the $2/3$ customer share. The retail base rate revenue sharing threshold amounts for 2004, 2003 and 2002 were $1.370 billion, $1.333 billion and $1.296 billion, respectively, and will increase $37 million in 2005. The Plan also provides that all retail base rate revenues above the retail base rate revenue caps established for each year will be refunded to retail customers on an annual basis. For 2002, the refund to customers was limited to 67.1% of the retail base rate revenues that exceeded the 2002 cap. The retail base revenue caps for 2004, 2003 and 2002 were $1.430 billion, $1.393 billion and $1.356 billion, respectively, and will increase $37 million in 2005. Any amounts above the retail base revenue caps will be refunded 100% to customers. At December 31, 2004, $9 million has been accrued and will be refunded to retail customers by March 2005. The 2003 revenue sharing amount was $18 million, and was refunded to customers

by April 30, 2004. Approximately $5 million was originally returned in March 2003 related to 2002 revenue sharing. However, in February 2003, the parties to the Agreement filed a motion seeking an order from the FPSC to enforce the Agreement. In this motion, the parties disputed PEF's calculation of retail revenue subject to refund and contended that the refund should be approximately $23 million. In July 2003, the FPSC ruled that PEF must provide an additional $18 million to its retail customers related to the 2002 revenue sharing calculation. PEF recorded this refund in the second quarter of 2003 as a charge against electric operating revenue and refunded this amount by October 2003.

The Agreement also provides that beginning with the in-service date of PEF's Hines Unit 2 and continuing through December 2005, PEF will be allowed to recover through the fuel cost recovery clause a return on average investment and depreciation expense for Hines Unit 2, to the extent such costs do not exceed the unit's cumulative fuel savings over the recovery period. Hines Unit 2 is a 516 MW combined-cycle unit that was placed in service in December 2003. PEF recovered $36 million through this clause related to Hines Unit 2.

In addition, PEF suspended retail accruals on its reserves for nuclear decommissioning and fossil dismantlement through December 2005. Additionally, for each calendar year during the term of the Agreement, PEF will record a $63 million depreciation expense reduction and may, at its option, record up to an equal annual amount as an offsetting accelerated depreciation expense. No accelerated depreciation expense was recorded during 2004 and 2003. In addition, PEF is authorized, at its discretion, to accelerate the amortization of certain regulatory assets over the term of the Agreement.

Under the terms of the Agreement, PEF agreed to continue the implementation of its four-year Commitment to Excellence Reliability Plan and expected to achieve a 20% improvement in its annual System Average Interruption Duration Index by no later than 2004. If this improvement level was not achieved for calendar years 2004 or 2005, PEF would have provided a refund of $3 million for each year the level is not achieved to 10% of its total retail customers served by its worst performing distribution feeder lines. PEF achieved this improvement level in 2004.

In January 2005, in anticipation of the expiration of its Stipulation and Settlement approved by the FPSC in 2002 to conclude PEF's then-pending rate case, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2006. In its notice, PEF requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. The request for increased base rates is based on the fact that PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines Unit 3 generation facility, extraordinary hurricane damage costs including capital costs which are not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of its strong customer growth. On February 7, 2005, the FPSC acknowledged receipt of PEF's notice and authorized minimum filing requirements and testimony to be filed May 1, 2005.

D. Regional Transmission Organizations and Standard Market Design

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 July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). If adopted as proposed, the rules set forth in the SMD NOPR would have materially altered the manner in which transmission and generation services are provided and paid for. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provided an overview of what the FERC intended to include in a final rule in the SMD NOPR docket. The White Paper retained the fundamental and most protested aspects of SMD NOPR, including mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. The FERC has not yet issued a final rule on SMD NOPR. The Company cannot predict the outcome of these matters or the effect that they may have on the GridSouth and GridFlorida proceedings currently ongoing before the FERC. By order issued December 22, 2004, the FERC terminated a portion of the proceedings regarding GridSouth. The GridSouth Companies asked the FERC for further clarification as to the portions of the GridSouth docket it intended to address. On March 2, 2005, the FERC affirmed that it only intended to close the mediation portion of the GridSouth docket. It is unknown what impact the future proceedings will have on the Company's earnings, revenues or prices.

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 currently scheduled to be presented at a FPSC workshop on May 25, 2005, with subsequent action by the FPSC to be thereafter determined.

The Company has $33 million and $4 million invested in GridSouth and GridFlorida, respectively, related to startup costs at December 31, 2004. The Company expects to recover these startup costs in conjunction with the GridSouth and GridFlorida original structures or in conjunction with any alternate combined transmission structures that emerge.

E. FERC Market Power Mitigation

A FERC order issued in November 2001 on certain unaffiliated utilities' triennial market-based wholesale power rate authorization updates required certain mitigation actions that those utilities would need to take for sales/purchases within their control areas and required those utilities to post information on their Web sites regarding their power systems' status. As a result of a request for rehearing filed by certain market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. 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 believes it would experience in passing one of the interim screens, on August 12, 2004, PEC notified the FERC that it would revise its Market-based Rate tariff to restrict it to sales outside PEC's control area and file a new cost-based tariff for sales within PEC's control area that incorporates the FERC's default cost-based rate methodologies for sales of one year or less. PEC anticipates making this filing in the first quarter of 2005. PEC does not anticipate that the current operations will be materially impacted by this change. Although the Company cannot predict the ultimate outcome of these changes, the Company does not anticipate that the current operations of PEC or PEF would be impacted materially if they were unable to sell power at market-based rates in their respective control areas.

Energy Delivery Capitalization Practice

The Company has reviewed its capitalization policies for its Energy Delivery business units in PEC and PEF. 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. The Company has implemented such changes effective January 1, 2005, which include more detailed classification of outage and emergency work and result in more precise estimation and a process of retesting 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 Company estimates that the combined impact for both utilities in 2005 will be that approximately $55 million of costs that would have been capitalized under the previous policies will be expensed. Pursuant to SFAS No. 71, PEC and PEF have informed the state regulators having jurisdiction over them of this change and that the new estimation process will be implemented effective January 1, 2005. The Company has also requested a method change from the IRS.

GOODWILL AND OTHER INTANGIBLE ASSETS

The Company performed the annual goodwill impairment test in accordance with FASB Statement No. 142, "Goodwill and Other Intangible Assets," for the CCO segment in the first quarter of 2004, and the annual goodwill impairment test for the PEC Electric and PEF segments in the second quarter of 2004, each of which indicated no impairment.

The changes in the carrying amount of goodwill, by reportable segment, are as follows:

(in millions)	PEC Electric	PEF	CCO	Corporate and Other	Total
Balance as of January 1, 2003	$1,922	$1,733	$64	$–	$3,719
Acquisitions	–	–	–	7	7
Balance as of December 31, 2003	**$1,922**	**$1,733**	**$64**	**$7**	**$3,726**
Purchase accounting adjustment	–	–	–	(7)	(7)
Balance as of December 31, 2004	**$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 Progress Telecommunications Corporation partial acquisition of EPIK and was reported in the Corporate and Other segment. The Company 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 (See Note 5A).

The gross carrying amount and accumulated amortization of the Company's intangible assets at December 31 are as follows:

	2004		2003	
(in millions)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Synthetic fuel intangibles	$134	$(80)	$140	$(64)
Power agreements acquired	221	(39)	221	(20)
Other	119	(18)	93	(13)
Total	$474	$(137)	$454	$(97)

In June 2004, the Company sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, one of its synthetic fuel operations. Approximately $6 million in synthetic fuel intangibles and $3 million in related accumulated amortization were included in the basis of the partnership interest sold.

All of the Company's intangibles 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 of the Internal Revenue Code (Section 29) in December 2007 (See Note 23E). The intangibles related to power agreements acquired are being amortized based on the economic benefits of the contracts (See Notes 5C and 5D). Other intangibles are primarily acquired customer contracts and permits that are amortized over their respective lives. Of the increase in other intangible assets, $24 million resulted from the minimum pension liability adjustment at December 31, 2004 (See Note 17).

Amortization expense recorded on intangible assets for the years ended December 31, 2004, 2003 and 2002 was, in millions, $42, $37 and $33, respectively. The estimated annual amortization expense for intangible assets for 2005 through 2009, in millions, is approximately $35, $36, $36, $18 and $18, respectively.

10. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

The Company applies SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2003 and 2002, the Company recorded pre-tax long-lived asset and investment impairments and other charges of approximately $38 million and $414 million, respectively.

Long-Lived Assets

Due to the reduction in coal production, the Company 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, the Company recorded asset impairments of $17 million on a pre-tax basis during the fourth quarter of 2003.

An estimated impairment of assets held for sale of $59 million is included in the 2002 amount, which relates to Railcar Ltd. (See Note 4C).

Due to the decline of the telecommunications industry and continued operating losses, the Company initiated an independent valuation study during 2002 to assess the recoverability of the long-lived assets of PTC and Caronet. Based on this assessment, the Company recorded asset impairments of $305 million on a pre-tax basis and other charges of $25 million on a pre-tax basis primarily related to inventory adjustments in the third quarter of 2002. This write-down constitutes a significant reduction in the book value of these long-lived assets.

The long-lived asset impairments include an impairment of property, plant and equipment, construction work in process and intangible assets. The impairment charge represents the difference between the fair value and carrying amount of these long-lived assets. The fair value of these assets was determined using a valuation study heavily weighted on the discounted cash flow methodology, using market approaches as supporting information.

B. Investments

The Company continually reviews its investments to determine whether a decline in fair value below the cost basis is other than temporary. In 2003, PEC's affordable housing investment (AHI) portfolio was reviewed and 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. As a result, PEC recorded an impairment of $18 million on a pre-tax basis during the fourth quarter of 2003. PEC also recorded an impairment of $3 million for a cost investment.

In May 2002, Interpath Communication, Inc., merged with a third party. As a result, the Company reviewed the Interpath investment for impairment and wrote off the remaining amount of its cost-basis investment in Interpath, recording a pre-tax impairment of $25 million in the third quarter of 2002. In the fourth quarter of 2002, the Company sold its remaining interest in Interpath for a nominal amount.

EQUITY

Common Stock

At December 31, 2004, the Company had approximately 63 million shares of common stock authorized by the Board of Directors that remained unissued and reserved, primarily to satisfy the requirements of the Company's stock plans. In 2002, the Board of Directors authorized meeting the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan and the Investor Plus Stock Purchase Plan with original issue shares. During 2004, 2003 and 2002, respectively, the Company issued approximately 1 million, 8 million and 2 million shares under these plans for net proceeds of approximately $62 million, $305 million and $86 million. The Company continues to meet the requirements of the restricted stock plan with issued and outstanding shares.

In November 2002, the Company issued 14.7 million shares of common stock for net cash proceeds of approximately $600 million, which were primarily used to retire commercial paper. In April 2002, the Company issued 2.5 million shares of common stock, valued at approximately $129 million, in conjunction with the purchase of Westchester (See Note 5D).

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2004, there were no significant restrictions on the use of retained earnings.

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

The Company sponsors the Progress Energy 401(k) Savings and Stock Ownership Plan (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 within the Company as of January 1, 2003, were PEC, PEF, PTC, Progress Fuels (Corporate) and Progress Energy Service Company. Effective December 19, 2003, (the PT LLC/EPIK merger date), PTC no longer participates in the 401(k) plan. The 401(k), which has Company matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Company 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 Company 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 Company 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 then allocated to participants, are fully deductible for income tax purposes.

There were 3.5 million and 4.0 million ESOP suspense shares at December 31, 2004 and 2003, respectively, with a fair value of $156 million and $183 million, respectively. ESOP shares allocated to plan participants totaled 12.6 million and 13.1 million at December 31, 2004 and 2003, respectively. The Company's 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 Company common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. The Company currently meets 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 $21 million, $20 million and $20 million for the years ended December 31, 2004, 2003 and 2002, respectively. Total matching and incentive cost totaled approximately $32 million, $35 million and $30 million for the years ended December 31, 2004, 2003 and 2002, respectively. The Company has a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from the Company 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.

STOCK OPTION AGREEMENTS

Pursuant to the Company's 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, the Company may grant options to purchase shares of common stock to directors, officers and eligible employees for up to 5 million and 15 million shares, respectively. Generally, options granted to employees vest one-third per year with 100% vesting at the end of year three, while options granted to directors vest 100% 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 the Company's common stock on the grant date. The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at grant date and, accordingly, no compensation expense has been recognized for any options granted during 2004, 2003 and 2002. The Company will begin expensing stock options on July 1, 2005, based on SFAS No. 123R (See Note 2). In 2004, however, the Company made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued.

The pro forma information presented in Note 1 regarding net income and earnings per share is required by SFAS No. 148. Under this statement, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The pro forma amounts presented in Note 1 have been determined as if the Company had accounted for its employee stock options under SFAS No. 123. 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	2002
Risk-free interest rate	**4.22%**	4.25%	4.14%
Dividend yield	**5.19%**	4.75%	5.20%
Volatility factor	**20.30%**	22.28%	24.98%
Weighted-average expected life of the options (in years)	**10**	10	10

The option valuation model requires the input of highly subjective assumptions, primarily stock price volatility, changes in which can materially affect the fair value estimate.

The options outstanding at December 31, 2004, 2003 and 2002 had a weighted-average remaining contractual life of 7.6, 8.7 and 9.3 years, respectively, and had exercise prices that ranged from $40.41 to $51.85. The tabular information for the option activity is as follows:

(option quantities in millions)	2004 Number of Options	2004 Weighted-Average Exercise Price	2003 Number of Options	2003 Weighted-Average Exercise Price	2002 Number of Options	2002 Weighted-Average Exercise Price
Options outstanding, January 1	**8.0**	**$43.54**	5.2	$42.84	2.3	$43.49
Granted	–	–	3.0	$44.70	2.9	$42.34
Forfeited	**(0.1)**	**$43.76**	(0.1)	$43.64	–	$43.71
Canceled	**(0.1)**	**$43.67**	(0.1)	$43.62		
Exercised	**(0.4)**	**$42.82**		$43.00	–	
Options outstanding, December 31	**7.4**	**$43.57**	8.0	$43.54	5.2	$42.84
Options exercisable, December 31 with a remaining contractual life of 7.6 years	**4.6**	**$43.35**	2.4	$43.09	0.8	$43.49
Weighted-average grant date fair value of options granted during the year		–		$7.16		$6.83

OTHER STOCK-BASED COMPENSATION PLANS

The Company has additional compensation plans for officers and key employees of the Company 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 program (RSA), both of which were established pursuant to the Company's 1997 Equity Incentive Plan and were continued under the Company's 2002 Equity Incentive Plan, as amended and restated as of July 10, 2002.

Under the terms of the PSSP, officers and key employees of the Company are granted 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 the Company's 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 the Company's results as compared to a peer group of utilities. Compensation expense is recognized over the vesting period based on the expected ultimate cash payout and is reduced by any forfeitures. Effective January 1, 2005, new awards granted pursuant to the PSSP will be payable in Company common stock rather than in cash.

The RSA program allows the Company to grant shares of restricted common stock to officers and key employees of the Company. 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. The weighted-average price of restricted shares at the grant date was $46.95, $39.53 and $44.27 in 2004, 2003 and 2002, respectively. Compensation expense is reduced by any forfeitures. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. Changes in restricted stock shares outstanding were:

	2004	2003	2002
Beginning balance	**944,883**	**950,180**	**674,511**
Granted	**154,500**	180,200	365,920
Vested	**(367,107)**	(151,677)	(75,200)
Forfeited	**(87,100)**	(33,820)	(15,051)
Ending balance	**645,176**	944,883	950,180

The total amount expensed for other stock-based compensation plans was $10 million, $27 million and $17 million in 2004, 2003 and 2002, respectively.

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 basic and dilutive purposes is as follows:

(in millions)	2004	2003	2002
Weighted-average common shares – basic	**242.2**	237.2	217.2
Restricted stock awards	**.8**	1.0	.8
Stock options	**.1**	–	.2
Weighted-average shares – fully diluted	**243.1**	238.2	218.2

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 of these shares totaled 3.6 million, 4.1 million and 4.8 million for the years ended December 31, 2004, 2003 and 2002, respectively. There were 3.0 million, 5.3 million and 92 thousand stock options outstanding at December 31, 2004, 2003 and 2002, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

11. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss are as follows:

(in millions)	**2004**	2003
Loss on cash flow hedges	**$(28)**	$(36)
Minimum pension liability adjustments	**(142)**	(16)
Foreign currency translation and other	**6**	2
Total accumulated other comprehensive loss	**$(164)**	$(50)

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

All of the Company's preferred stock was issued by its subsidiaries and was not subject to mandatory redemption. Preferred stock outstanding at December 31, 2004 and 2003 consisted of the following:

(in millions, except share data and par value)	
Progress Energy Carolinas, Inc.	
Authorized –	
300,000 shares, cumulative, $100 par value Preferred Stock;	
20,000,000 shares, cumulative, $100 par value Serial Preferred Stock	
$5.00 Preferred – 236,997 shares outstanding (redemption price $110.00)	$24
$4.20 Serial Preferred – 100,000 shares outstanding (redemption price $102.00)	10
$5.44 Serial Preferred – 249,850 shares outstanding (redemption price $101.00)	25
	$59
Progress Energy Florida, Inc.	
Authorized –	
4,000,000 shares, cumulative, $100 par value Preferred Stock;	
5,000,000 shares, cumulative, no par value Preferred Stock;	
1,000,000 shares, $100 par value Preference Stock; $100 par value Preferred Stock:	
4.00% – 39,980 shares outstanding (redemption price $104.25)	$4
4.40% – 75,000 shares outstanding (redemption price $102.00)	8
4.58% – 99,990 shares outstanding (redemption price $101.00)	10
4.60% – 39,997 shares outstanding (redemption price $103.25)	4
4.75% – 80,000 shares outstanding (redemption price $102.00)	8
	$34
Total Preferred Stock of Subsidiaries	$93

13. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31, the Company's long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2004):

(in millions)		2004	2003
Progress Energy, Inc.			
Senior unsecured notes, maturing 2006-2031	6.90%	**$4,300**	**$4,800**
Draws on revolving credit agreement, expiring 2009	3.19%	**160**	–
Unamortized fair value hedge gain, net		**12**	**19**
Unamortized premium and discount, net		**(23)**	**(27)**
		4,449	4,792
Progress Energy Carolinas, Inc.			
First mortgage bonds, maturing 2005-2033	6.33%	**1,600**	1,900
Pollution control obligations, maturing 2017-2024	1.98%	**669**	708
Unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes, maturing 2008	6.65%	**300**	300
Unamortized premium and discount, net		**(19)**	(22)
		3,050	3,386
Progress Energy Florida, Inc.			
First mortgage bonds, maturing 2008-2033	5.60%	**1,330**	1,330
Pollution control obligations, maturing 2018-2027	1.67%	**241**	241
Medium-term notes, maturing 2005-2028	6.76%	**337**	379
Draws on revolving credit agreement, expiring 2006	2.95%	**55**	–
Unamortized premium and discount, net		**(3)**	(3)
		1,960	1,947
Florida Progress Funding Corporation (See Note 19)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(39)**	(39)
		270	270
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2006-2008	6.84%	**140**	165
Miscellaneous notes		**1**	1
		141	166
Progress Genco Ventures, LLC			
Variable rate project financing, maturing 2007		**–**	241
Current portion of long-term debt		**(349)**	(868)
Total long-term debt		**$9,521**	$9,934

At December 31, 2004, the Company had committed lines of credit used to support its commercial paper borrowings. The Progress Energy five-year credit facility and the PEF three-year credit facility are included in long-term debt. All other credit facilities are included in short-term obligations. At December 31, 2004, the Company had $260 million outstanding under its credit facilities classified as short-term obligations at a weighted-average interest rate of 3.18%. No amount was outstanding under the Company's committed lines of credit at December 31, 2003. The Company is required to pay minimal annual commitment fees to maintain its credit facilities.

The following table summarizes the Company's credit facilities:

(in millions) Company	Description	Total	Outstanding	Available
Progress Energy, Inc.	5-Year (expiring 8/5/09)	$1,130	$160	$970
Progress Energy Carolinas, Inc.	364-Day (expiring 7/27/05)	165	90	75
Progress Energy Carolinas, Inc.	3-Year (expiring 7/31/05)	285	–	285
Progress Energy Florida, Inc.	364-Day (expiring 3/29/05)	200	170	30
Progress Energy Florida, Inc.	3-Year (expiring 4/01/06)	200	55	145
Less: amounts reserved[a]				(574)
Total credit facilities		$1,980	$475	$931

[a] To the extent amounts are reserved for commercial paper outstanding or backing letters of credit, they are not available for additional borrowings.

At December 31, 2004 and 2003, the Company had $424 million and $4 million, respectively, of outstanding commercial paper and other short-term debt classified as short-term obligations. The weighted-average interest rates of such short-term obligations at December 31, 2004 and 2003 were 2.77% and 2.25%, respectively. At December 31, 2004, the Company has reserved $150 million of its lines of credit for backing of letters of credit.

Both Progress Energy and PEF have an uncommitted bank bid facility authorizing them to borrow and reborrow, and have loans outstanding at any time, up to $300 million and $100 million, respectively. These bank bid facilities were not drawn at December 31, 2004.

On January 31, 2005, Progress Energy, Inc., entered into a new $600 million revolving credit agreement, which expires December 30, 2005. This facility was added to provide additional liquidity during 2005 due in part to storm restoration costs incurred in Florida during 2004. The credit agreement includes a defined maximum total debt to total capital ratio of 68% and a minimum interest coverage ratio of 2.5 to 1. The credit agreement also contains various cross-default and other acceleration provisions. On February 4, 2005, $300 million was drawn under the new facility to reduce commercial paper and bank loans outstanding.

The combined aggregate maturities of long-term debt for 2005 through 2009 are approximately $349 million, $963 million, $674 million, $827 million and $560 million, respectively.

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy's, PEC's and PEF's credit lines contain various terms and conditions that could affect the Company's ability to borrow under these facilities. These include maximum debt to total capital ratios, interest coverage tests, 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, 2004, the maximum and calculated ratios for the companies, pursuant to the terms of the agreements, are as follows:

Company	Maximum Ratio	Actual Ratio[a]
Progress Energy, Inc.	65%	60.7%
Progress Energy Carolinas, Inc.	65%	52.3%
Progress Energy Florida, Inc.	65%	50.8%

[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's 364-day credit facility and both PEF's 364-day and three-year credit facilities have a financial covenant for interest coverage. The covenants require Progress Energy's and PEF's earnings before interest, taxes, and depreciation and amortization to interest expense ratio to be at least 2.5 to 1 and 3 to 1, respectively. For the year ended December 31, 2004, the ratios were 4.00 to 1 and 7.93 to 1 for the Company and PEF, respectively.

In March 2005, Progress Energy, Inc.'s five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65% to 68% in anticipation of the potential impacts of proposed accounting rules for uncertain tax positions. See Notes 2 and 23E.

MATERIAL ADVERSE CHANGE CLAUSE

The credit facilities of Progress Energy, PEC, and PEF include a provision under which lenders could refuse to advance funds in the event of a material adverse change (MAC) in the borrower's financial condition. Pursuant to

the terms of Progress Energy's five-year credit facility, even in the event of a MAC, Progress Energy may continue to borrow funds so long as the proceeds are used to repay maturing commercial paper balances.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of $10 million. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of $10 million, the lenders could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy's cross-default provision applies only to Progress Energy and its significant subsidiaries (i.e., PEC, Florida Progress, PEF, Progress Capital Holdings, Inc. (PCH) and Progress Fuels).

Additionally, certain of Progress Energy's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of $25 million; these provisions apply only to other obligations of Progress Energy, primarily commercial paper issued by the holding company, 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 the Company's indebtedness also limit its ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy'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'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, 2004, 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% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. At December 31, 2004, PEC's common stock equity was approximately 52.2% 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, 2004, 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 (a) all credits to retained earnings since April 30, 1944, plus (b) 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.

PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. On December 31, 2004, PEF's common stock equity was approximately 54.4% 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, 2004, PEC and PEF had a total of approximately $3.84 billion 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. Progress Genco Ventures, LLC (Genco) Bank Facility

In December 2004, Genco repaid its bank facility and recorded a $9 million pre-tax loss ($6 million after-tax) in other, net on the extinguishment. At that time, the related $195 million notional amount of interest rate collars in place to hedge floating interest rate exposure on the bank facility was terminated and pre-tax deferred losses of $6 million ($4 million after-tax) were reclassified into

earnings in other, net due to the discontinuance of the hedges. The facility was obtained to be used exclusively for expansion of its nonregulated generation portfolio. Borrowings under this facility were secured by the assets in the generation portfolio. The facility was for up to $260 million, of which $241 million had been drawn at December 31, 2003. Borrowings under the facility were restricted for the operations, construction, repayments and other related charges of the credit facility for the development projects. Cash held and restricted to operations was $24 million at December 31, 2003, and was included in other current assets. Cash held and restricted for long-term purposes was $9 million at December 31, 2003, and was included in other assets and deferred debits on the Consolidated Balance Sheets.

E. Guarantees of Subsidiary Debt

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

F. Hedging Activities

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

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of cash and cash equivalents and short-term obligations approximate fair value due to the short maturities of these instruments. At December 31, 2004, and 2003, investments in company-owned life insurance and other benefit plan assets, with carrying amounts of approximately $220 million and $210 million, respectively, 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. Other instruments, including short-term investments, are presented at fair value in accordance with GAAP. The carrying amount of the Company's long-term debt, including current maturities, was $9.870 billion and $10.802 billion at December 31, 2004 and 2003, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $10.843 billion and $11.917 billion at December 31, 2004 and 2003, respectively.

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 6D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. 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.

15. INCOME TAXES

Deferred income taxes have been provided 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, "Accounting for Income Taxes," (SFAS No. 109) is different from the recovery of taxes by PEC and PEF 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 are:

(in millions)	**2004**	2003
Current deferred tax asset		
Unbilled revenue	**$35**	$18
Other	**86**	69
Total current deferred tax asset	**121**	87
Noncurrent deferred tax asset (liability)		
Investments	**73**	8
Supplemental executive retirement plans	**31**	30
Other post-employment benefits (OPEB)	**126**	119
Other pension plans	**(15)**	(97)
Goodwill	**34**	46
Accumulated depreciation and property cost differences	**(1,374)**	(1,436)
Deferred costs	**(13)**	26
Deferred storm costs	**(113)**	–
Deferred fuel	**(55)**	31
Federal income tax credit carry forward	**779**	683
State net operating loss carry forward	**47**	42
Valuation allowance	**(47)**	(42)
Miscellaneous other temporary differences, net	**43**	(16)
Total noncurrent deferred tax liabilities	**(484)**	(606)
Less amount included in other assets and deferred debits	**10**	9
Net noncurrent deferred tax liabilities	**$(494)**	$(615)

Total deferred income tax liabilities were $2,797 million and $2,662 million at December 31, 2004 and 2003, respectively. Total deferred income tax assets were

$2,434 million and $2,143 million at December 31, 2004 and 2003, respectively. Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2004 and 2003 include $105 million and $86 million, respectively, related to probable tax liabilities on which the Company accrues interest that would be payable with the related tax amount in future years.

The federal income tax credit carry forward at December 31, 2004, consists of $749 million of alternative minimum tax credit with an indefinite carry forward period and $30 million of general business credit with a carry forward period that will begin to expire in 2020.

As of December 31, 2004, the Company had a state net operating loss carry forward of $79 million, which will begin to expire in 2007.

The Company established additional valuation allowances of $5 million during 2004 and 2003 and $12 million during 2002, due to the uncertainty of realizing certain future state tax benefits. The Company believes 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. Progress Energy decreased its 2004 beginning of the year valuation allowance by $8 million for a change in circumstances related to net operating losses.

The Company establishes accruals for certain tax contingencies when, despite the belief that the Company's tax return positions are fully supported, the Company believes that certain positions may be challenged and that it is probable the Company's positions may not be fully sustained. The Company is under continuous examination by the Internal Revenue Service and other tax authorities and accounts for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2004 and 2003, respectively, the Company had recorded $60 million and $56 million of tax contingency reserves, excluding accrued interest and penalties, which are included in other current liabilities on the Consolidated Balance Sheets. Considering all tax contingency reserves, the Company does not expect the resolution of these matters to have a material impact on its financial position or result of operations. All tax contingency reserves relate to capitalization and basis issues and do not relate to any potential disallowances of tax credits from synthetic fuel production (See Note 23E).

Reconciliations of the Company's effective income tax rate to the statutory federal income tax rate are:

	2004	2003	2002
Effective income tax rate	**13.5%**	(15.8)%	(40.0)%
State income taxes, net of federal benefit	**(6.9)**	(3.3)	(8.2)
AFUDC amortization	**(0.5)**	(1.4)	(5.2)
Federal tax credits	**25.6**	50.4	78.0
Investment tax credit amortization	**1.6**	2.3	4.7
ESOP dividend deduction	**1.8**	2.1	3.8
Other differences, net	**(0.1)**	0.7	1.9
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense (benefit) applicable to continuing operations is comprised of:

(in millions)	**2004**	2003	2002
Current – federal	**$127**	$127	$195
state	**76**	54	67
Deferred – federal	**(84)**	(255)	(379)
state	**10**	(21)	(23)
Investment tax credit	**(14)**	(16)	(18)
Total income tax expense (benefit)	**$115**	$(111)	$(158)

The company has recognized tax benefits from state net operating loss carry forwards in the amount of $7 million during 2004 and $3 million during 2003 and 2002.

The Company, through its subsidiaries, is a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied (See Note 23E).

16. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of FPC during 2000, the Company issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right 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, 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, 2004 and 2003, was $13 million and $23 million, respectively.

17. BENEFIT PLANS

A. Postretirement Benefits

The Company and some of its subsidiaries have a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees. The Company also has supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, the Company and some of its subsidiaries provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. The Company uses a measurement date of December 31 for its pension and OPEB plans.

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

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2004**	2003	2002	**2004**	2003	2002
Service cost	**$54**	$52	$45	**$12**	$15	$13
Interest cost	**110**	108	106	**31**	33	32
Expected return on plan assets	**(155)**	(144)	(161)	**(5)**	(4)	(5)
Amortization of actuarial (gain) loss	**21**	25	2	**4**	5	1
Other amortization, net	**–**	–	–	**1**	4	4
Net periodic cost/(benefit)	**30**	41	(8)	**43**	53	45
Additional cost/(benefit) recognition (Note 17B)	**(16)**	(18)	(7)	**2**	2	2
Net periodic cost/(benefit) recognized	**$14**	$23	$(15)	**$45**	$55	$47

The net periodic cost for other postretirement benefits decreased during 2004 due to the implementation of FASB Staff Position 106-2 (See Note 2). In addition to the net periodic cost and benefit reflected above, in 2003 the Company 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.

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% 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, the Company uses a five-year averaging method for a portion of its pension assets and fair value for the remaining portion. The Company has historically used the five-year averaging method. When the Company acquired Florida Progress in 2000, it retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

Reconciliations of the changes in the plans' benefit obligations and the plans' funded status are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2004**	2003	**2004**	2003
Projected benefit obligation at January 1	**$1,772**	$1,694	**$472**	$514
Service cost	**54**	52	**12**	15
Interest cost	**110**	108	**31**	33
Disposition of NCNG	**–**	(39)	**–**	(13)
Benefit payments	**(98)**	(94)	**(23)**	(24)
Plan amendment	**21**	–	**–**	–
Actuarial loss (gain)	**102**	51	**46**	(53)
Obligation at December 31	**1,961**	1,772	**538**	472
Fair value of plan assets at December 31	**1,774**	1,631	**70**	65
Funded status	**(187)**	(141)	**(468)**	(407)
Unrecognized transition obligation	**–**	–	**10**	25
Unrecognized prior service cost	**24**	4	**6**	7
Unrecognized net actuarial loss	**530**	505	**94**	40
Minimum pension liability adjustment	**(470)**	(23)	**–**	–
Prepaid (accrued) cost at December 31, net (Note 17B)	**$(103)**	$345	**$(358)**	$(335)

The 2003 OPEB obligation information above has been restated due to the implementation of FASB Staff Position 106-2 (See Note 2).

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 net prepaid pension cost of $345 million at December 31, 2003, is recognized in the Consolidated Balance Sheets as prepaid pension cost of $462 million and accrued benefit cost of $117 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 $1.72 billion and $125 million at December 31, 2004 and 2003, respectively. Those plans had accumulated benefit obligations totaling $1.71 billion and $117 million at December 31, 2004 and 2003, respectively, $1.57 billion of plan assets at December 31, 2004, and no plan assets at December 31, 2003. The total accumulated benefit obligation for pension plans was $1.90 billion and $1.72 billion at December 31, 2004 and 2003, respectively. The accrued OPEB cost is included in accrued pension and other benefits in the Consolidated Balance Sheets.

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 17B), a $67 million charge to a regulatory asset pursuant to a recent FPSC order and a pre-tax charge of $229 million to accumulated other comprehensive loss, a component of common stock equity. A minimum pension liability adjustment of $23 million, related to the supplementary defined benefit pension plans, was recorded at December 31, 2003. This adjustment is offset by a corresponding pre-tax amount in accumulated other comprehensive loss.

Reconciliations of the fair value of plan assets are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2004**	2003	**2004**	2003
Fair value of plan assets January 1	**$1,631**	$1,364	**$65**	$52
Actual return on plan assets	**211**	391	**8**	12
Disposition of NCNG	**–**	(35)	**–**	–
Benefit payments	**(98)**	(94)	**(23)**	(24)
Employer contributions	**30**	5	**20**	25
Fair value of plan assets at December 31	**$1,774**	$1,631	**$70**	$65

In the table above, substantially all employer contributions represent benefit payments made directly from Company assets except for the 2004 pension amount. The remaining benefits payments were made directly from plan assets. In 2004, the Company made a required contribution of approximately $24 million directly to pension plan assets. The OPEB benefit payments represent the net Company cost after participant contributions. Participant contributions represent approximately 20% of gross benefit payments.

The asset allocation for the Company's plans at the end of 2004 and 2003 and the target allocation for the plans, by asset category, are as follows:

	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	2005	**2004**	2003	2005	**2004**	2003
Equity – domestic	48%	**47%**	49%	34%	**34%**	35%
Equity – international	15%	**21%**	22%	11%	**15%**	16%
Debt – domestic	12%	**9%**	11%	37%	**35%**	37%
Debt – international	10%	**11%**	11%	7%	**8%**	7%
Other	15%	**12%**	7%	11%	**8%**	5%
Total	100%	**100%**	100%	100%	**100%**	100%

The Company sets 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, the Company employs external investment managers who have complementary investment philosophies and approaches. Tactical shifts (plus or minus 5%) 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.

In 2005, the Company expects to make no required 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 2005 through 2009 and in total for 2010-2014, in millions, are approximately $113, $110, $115, $124, $131 and $794, respectively. The expected benefit payments for the OPEB plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately $32, $34, $37, $39, $41 and $230, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from Company assets. The benefit payment amounts reflect the net cost to the Company after any participant contributions. The Company expects to begin receiving prescription drug-related federal subsidies in 2006 (See Note 2), and the expected subsidies for 2006 through 2009 and in total for 2010-2014, in millions, are approximately $3, $3, $3, $4 and $24, respectively. The expected benefit payments above do not reflect the potential effects of a 2005 voluntary enhanced retirement program (See Note 24).

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2004**	2003	**2004**	2003
Discount rate	**5.90%**	6.30%	**5.9%**	6.30%
Rate of increase in future compensation				
Bargaining	**3.50%**	3.50%	–	–
Supplementary plans	**5.25%**	5.00%	–	–
Initial medical cost trend rate for pre-Medicare benefits	–	–	**7.25%**	7.25%
Initial medical cost trend rate for post-Medicare benefits	–	–	**7.25%**	7.25%
Ultimate medical cost trend rate	–	–	**5.00%**	5.25%
Year ultimate medical cost trend rate is achieved	–	–	**2008**	2009

The Company's primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4. Therefore, effective December 31, 2003, the Company 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.

The following weighted-average actuarial assumptions were used in the calculation of the net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2004**	2003	2002	**2004**	2003	2002
Discount rate	**6.30%**	6.60%	7.50%	**6.30%**	6.60%	7.50%
Rate of increase in future compensation						
Bargaining	**3.50%**	3.50%	3.50%	–	–	–
Nonbargaining	–	4.00%	4.00%	–	–	–
Supplementary plans	**5.00%**	4.00%	4.00%	–	–	–
Expected long-term rate of return on plan assets	**9.25%**	9.25%	9.25%	**8.50%**	8.45%	8.20%

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%. The Company has chosen to use an expected long-term rate of 9.25%.

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. Assuming a 1% increase in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would increase by $1 million, and the OPEB obligation at December 31, 2004, would increase by $30 million. Assuming a 1% decrease in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would decrease by $1 million, and the OPEB obligation at December 31, 2004, would decrease by $26 million.

B. FPC Acquisition

During 2000, the Company completed the acquisition of FPC. FPC's pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of FPC's nonbargaining unit benefit plans were merged with those of the Company 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, 2004, and 2003 (See Note 8A). In addition, a portion of the prepaid pension cost reflected in the table above has a corresponding regulatory liability (See Note 8A). 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.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

Under its risk management policy, the Company 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. The Company minimizes 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 the consolidated financial position or consolidated results of operations of the Company.

A. Commodity Derivatives

GENERAL

Most of the Company's commodity contracts are not derivatives pursuant to SFAS No. 133 or do not qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

During 2003 the FASB reconsidered an interpretation of SFAS No. 133 related to the pricing of contracts that include broad market indices (e.g., CPI). In particular, that guidance discussed whether the pricing in a contract that contains broad market indices could qualify as a normal purchase or sale (the normal purchase or sale term is a defined accounting term, and may not, in all cases, indicate whether the contract would be "normal" from an operating entity viewpoint). The FASB issued final superseding guidance (DIG Issue C20) on this issue effective October 1, 2003, for the Company. DIG Issue C20 specifies new pricing-related criteria for qualifying as a normal purchase or sale, and it required a special transition adjustment as of October 1, 2003.

PEC determined that it had one existing "normal" contract that was affected by DIG Issue C20. Pursuant to the provisions of DIG Issue C20, PEC recorded a pre-tax fair value loss transition adjustment of $38 million ($23 million after-tax) in the fourth quarter of 2003, which was reported as a cumulative effect of a change in accounting principle. The subject contract meets the DIG Issue C20 criteria for normal purchase or sale and,

therefore, was designated as a normal purchase as of October 1, 2003. The original liability of $38 million associated with the fair value loss is being amortized to earnings over the term of the related contract. At December 31, 2004 and 2003, the remaining liability was $26 million and $35 million, respectively.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, are entered into 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. The Company manages open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to results of operations during 2004, 2003 or 2002, and the Company did not have material outstanding positions in such contracts at December 31, 2004 and 2003.

In 2004, PEF entered into derivative instruments related to its exposure to price fluctuations on fuel oil purchases. At December 31, 2004, the fair values of these 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. These instruments receive regulatory accounting treatment. Gains are recorded in regulatory liabilities and losses are recorded in regulatory assets.

CASH FLOW HEDGES

Progress Energy's 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 for the Company's forecasted purchases and sales. At December 31, 2004, the maximum period over which the Company is hedging exposures to the price variability of natural gas is 10 years.

The total fair value of commodity cash flow hedges at December 31, 2004 and 2003 was as follows:

(millions of dollars)	**2004**	2003
Fair value of assets	**$–**	$–
Fair value of liabilities	**(15)**	(12)
Fair value, net	**$(15)**	$(12)

The ineffective portion of commodity cash flow hedges was not material to the Company's results of operations for 2004, 2003 or 2002. At December 31, 2004, there were $9 million of after-tax deferred losses in accumulated other comprehensive income (OCI), of which $5 million is expected to be reclassified to earnings during the next 12 months as the hedged transactions occur. Gains and losses are recorded net in operating revenues. As part of the divestiture of Winchester Production Company, Ltd., assets in 2004, $7 million of after-tax deferred losses were reclassified into earnings due to discontinuance of the related cash flow hedges and recorded against the gain on sale. Due to the volatility of the commodities markets, the value in OCI is subject to change prior to its reclassification into earnings.

8 Interest Rate Derivatives – Fair Value or Cash Flow Hedges

The Company uses cash flow hedging strategies to hedge variable interest rates on long-term and short-term debt and to hedge interest rates with regard to future fixed-rate debt issuances. Gains and losses are recorded in OCI and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. The Company uses fair value hedging strategies to manage its exposure to fixed interest rates on long-term debt. 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.

The fair values of open position interest rate hedges at December 31, 2004 and 2003 were as follows:

(in millions)	**2004**	2003
Interest rate cash flow hedges	**$(2)**	$(6)
Interest rate fair value hedges	**$3**	$(4)

CASH FLOW HEDGES

The following table presents selected information related to the Company's interest rate cash flow hedges included in accumulated OCI at December 31, 2004:

Accumulated Other Comprehensive Income/**(Loss)**, net of **tax**[a] (millions of **dollars**)	Portion Expected to be Reclassified to Earnings during the Next 12 Months[b]
$(19)	$(4)

(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.

As of December 31, 2004, PEC had $110 million notional amount of pay-fixed forward swaps to hedge its exposure to interest rates with regard to future issuances of debt (pre-issue hedges) and $21 million notional amount of pay-fixed forward starting swaps to hedge its exposure to interest rates with regard to an upcoming railcar lease. On February 4, 2005, PEC entered another $50 million notional amount of its pre-issue hedges. All the swaps have a computational period of 10 years. PEC held no interest rate cash flow hedges at December 31, 2003. The ineffective portion of interest rate cash flow hedges was not material to the Company's results of operations for 2004 and 2003.

In December 2004, Progress Ventures, Inc. (PVI), a wholly owned subsidiary of Progress Energy, terminated $195 million notional amount of interest rate collars in place to hedge floating interest rate exposure associated with variable-rate long-term debt. The related debt was also extinguished in December 2004 (See Note 13). Pre-tax deferred losses of $6 million ($4 million after-tax) were reclassified into earnings in other, net due to discontinuance of these cash flow hedges.

At December 31, 2004 and 2003, Progress Energy, Inc., held interest rate cash flow hedges, with a total notional amount of $200 million and $400 million, respectively, related to projected outstanding balances of commercial paper. The fair value of the hedges at December 31, 2004, was not material to the Company's financial condition and at December 31, 2003, was $5 million. The hedges held at December 31, 2003, were terminated during the year. Amounts in accumulated other comprehensive income related to these terminated hedges will be reclassified to earnings as the hedged interest payments occur.

FAIR VALUE HEDGES

As of December 31, 2004 and 2003, Progress Energy had $150 million notional amount and $850 million notional amount, respectively, of fixed rate debt swapped to floating rate debt by executing interest rate derivative agreements. These agreements expire on various dates through March 2011. During 2004, Progress Energy entered into $350 million notional amount and terminated $1.05 billion notional amount of interest rate swap agreements.

At December 31, 2004 and 2003, the Company had $9 million and $23 million, 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 2011 coinciding with the maturities of the related debt instruments.

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 these transactions is the cost of replacing the agreements at current market rates.

19. RELATED PARTY TRANSACTIONS

As a part of normal business, Progress Energy and certain subsidiaries 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. As of December 31, 2004, Progress Energy and its subsidiaries' guarantees include: $270 million supporting commodity transactions, $181 million to support nuclear decommissioning, $536 million related to power supply agreements and $182 million for guarantees supporting other agreements of subsidiaries. Progress Energy also purchased $92 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $50 million. Florida Progress also fully guarantees the medium-term notes outstanding for Progress Capital, a wholly owned subsidiary of Florida Progress (See Note 13). At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Balance Sheets.

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 $331 million, $346 million and $329 million for the years ended December 31, 2004, 2003 and 2002, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income.

Florida Progress Funding Corporation's (Funding Corp.) $309 million 7.10% Junior Subordinated Deferrable Interest Notes (Subordinated Notes) are due to FPC Capital I (the Trust). The Trust was established for the sole purpose of issuing $300 million Preferred Securities and using the proceeds thereof to purchase from Funding Corp. its Subordinated Notes due 2039. The

Company has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, the Company has 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 (Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by the Company of the Trust's obligations under the Preferred Securities. The Subordinated Notes and the Notes Guarantee are the sole assets of the Trust. 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.

The Company sold NCNG to Piedmont Natural Gas Company, Inc. on September 30, 2003 (See Note 4E). Prior to disposition, NCNG sold natural gas to affiliates. During the years ended December 31, 2003 and 2002, sales of natural gas to affiliates amounted to $11 million and $20 million, respectively. These revenues are included in discontinued operations on the Consolidated Statements of Income.

20. FINANCIAL INFORMATION BY BUSINESS SEGMENT

The Company currently provides services through the following business segments: PEC Electric, PEF, Fuels, CCO and Rail Services. Prior to 2004, other nonregulated business activities were reported separately in the Other segment. These reportable segment changes reflect the current reporting structure. For comparative purposes, the results have been restated to align with the current presentation.

PEC Electric and PEF are primarily engaged in the generation, transmission, distribution and sale of electric energy in portions of North Carolina, South Carolina and Florida. These electric operations are subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the FPSC. These electric operations also distribute and sell electricity to other utilities, primarily on the east coast of the United States.

Fuels operations, which are located throughout the United States, are involved in natural gas drilling and production, coal terminal services, coal mining, synthetic fuel production and fuel transportation and delivery.

CCO's operations, which are located in the southeastern United States, include nonregulated electric generation operations and marketing activities.

Rail Services' operations include railcar repair, rail parts reconditioning and sales, railcar leasing and sales and scrap metal recycling. These activities include maintenance and reconditioning of salvageable scrap components of railcars, locomotive repair and right-of-way maintenance. Rail Services' operations are located in the United States, Canada and Mexico.

In addition to these reportable operating segments, the Company has Corporate and Other activities that include holding company and service company operations as well as other nonregulated business areas. These nonregulated business areas include telecommunications and energy service operations 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." Included in the 2004 losses is a $43 million pre-tax ($29 million after-tax) settlement agreement that SRS reached with the San Francisco United School District related to civil proceedings. Included in the 2002 losses are asset impairments and certain other after-tax charges related to the telecommunications operations of $225 million. The operations of NCNG were reclassified to discontinued operations and therefore are not included in the results from continuing operations during the periods reported. The profit or loss of the identified segments plus the loss of Corporate and Other represents the Company's total income from continuing operations.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between Fuels and PEF, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and Fuels are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits for all three years presented were not significant.

(in millions)	PEC Electric	PEF	Fuels	CCO	Rail Services	Corporate and Other	Eliminations	Totals
Year ended December 31, 2004								
Revenues								
Unaffiliated	**$3,628**	**$3,525**	**$1,179**	**$240**	**$1,130**	**$70**	**$–**	**$9,772**
Intersegment	**–**	**–**	**331**	**–**	**1**	**441**	**(773)**	**–**
Total revenues	**3,628**	**3,525**	**1,510**	**240**	**1,131**	**511**	**(773)**	**9,772**
Depreciation and amortization	**570**	**281**	**93**	**58**	**21**	**45**	**–**	**1,068**
Total interest charges, net	**192**	**114**	**22**	**17**	**27**	**361**	**(86)**	**647**
Gain on sale of assets	**–**	**–**	**54**	**–**	**–**	**3**	**–**	**57**
Income tax expense (benefit)[a]	**237**	**174**	**(230)**	**(1)**	**15**	**(80)**	**–**	**115**
Segment profit (loss)	**464**	**333**	**180**	**(4)**	**16**	**(236)**	**–**	**753**
Total assets	**10,590**	**7,924**	**986**	**1,709**	**596**	**17,741**	**(13,553)**	**25,993**
Capital and investment expenditures	**519**	**480**	**157**	**25**	**40**	**14**	**–**	**1,235**
Year ended December 31, 2003								
Revenues								
Unaffiliated	$3,589	$3,152	$928	$170	$846	$56	$–	$8,741
Intersegment		–	346	–	1	446	(793)	–
Total revenues	3,589	3,152	1,274	170	847	502	(793)	8,741
Depreciation and amortization	562	307	80	42	20	29	–	1,040
Total interest charges, net	197	91	23	4	29	356	(72)	628
Impairment of long-lived assets and investments	11	–	17	–	–	10	–	38
Income tax expense (benefit)[a]	238	147	(415)	8	2	(46)	(45)	(111)
Segment profit (loss)	515	295	235	20	(1)	(253)	–	811
Total assets	10,748	7,280	1,142	1,747	586	17,955	(13,365)	26,093
Capital and investment expenditures	445	526	309	338	103	35	–	1,756
Year ended December 31, 2002								
Revenues								
Unaffiliated	$3,539	$3,062	$607	$92	$714	$77	$–	$8,091
Intersegment	–	–	329	–	5	418	(752)	
Total revenues	3,539	3,062	936	92	719	495	(752)	8,091
Depreciation and amortization	524	295	47	20	20	32	–	938
Total interest charges, net	212	106	24	(12)	33	351	(81)	633
Impairment of long-lived assets and investments				–	59	330	–	389
Income tax expense (benefit)[a]	237	163	(373)	16	(16)	(191)	6	(158)
Segment profit (loss)	513	323	176	27	(42)	(445)	–	552
Total assets	10,139	6,678	934	1,452	529	15,872	(11,886)	23,718
Capital and investment expenditures	619	550	170	682	8	73	–	2,102

[a] Amounts include income tax benefit reallocation from holding company to profitable subsidiaries according to an SEC order.

Geographic Data

(in millions)	U.S.	Canada	Mexico	Consolidated
2004				
Consolidated revenues	**$9,644**	**$112**	**$16**	**$9,772**
2003				
Consolidated revenues	$8,624	$103	$14	$8,741
2002				
Consolidated revenues	$7,984	$93	$14	$8,091

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. The components of other, net as shown on the Consolidated Statements of Income for the years ended December 31 are as follows:

(in millions)	2004	2003	2002
Other Income			
Nonregulated energy and delivery services income	**$32**	$27	$33
DIG Issue C20 amortization (Note 18A)	9	7	–
Contingent value obligation unrealized gain (Note 16)	**9**	–	28
Investment gains	–	5	–
AFUDC equity	**11**	14	8
Gain on sale of property and partnership investments	**12**	25	12
Other	**34**	17	42
Total other income	**$107**	$90	$123
Other Expense			
Nonregulated energy and delivery services expenses	**$20**	$20	$29
Donations	**10**	12	19
Investment losses	**6**	–	–
Contingent value obligation unrealized loss (Note 16)	–	9	–
Loss from equity investments	**6**	40	21
Loss on debt extinguishment and interest rate collars (Note 13D)	**15**	–	–
Other	**42**	25	27
Total other expense	**$99**	$106	$96
Other, net	**$8**	$(16)	$27

Nonregulated energy and delivery services include power protection **services** and **mass market** programs (surge protection, appliance services and area light sales) and delivery, transmission and substation work for other utilities.

22. ENVIRONMENTAL MATTERS

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

Hazardous and Solid Waste Management

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North and South Carolina, have similar types of legislation. The Company and its subsidiaries are periodically notified by regulators including the EPA and various state agencies of their involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which the Company has been notified by the EPA, the State of North Carolina or the State of Florida of its potential liability, as described below in greater detail. The Company also is currently in the process of assessing potential costs and exposures at other sites. For all sites, as assessments are developed and analyzed, the Company will accrue costs for the sites to the extent the costs are probable and can be reasonably estimated. A discussion of sites by legal entity follows.

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.

PEC, PEF and Progress Fuels Corporation have filed claims with the Company's general liability insurance carriers to recover costs arising from actual or potential environmental liabilities. Some claims have been settled and others are still pending. While the Company cannot predict the outcome of these matters, the outcome is not expected to have a material effect on the consolidated financial position or results of operations.

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 costs.

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, North Carolina. The EPA offered PEC and 34 other PRPs the opportunity to

negotiate cleanup of the site and reimbursement of less than $2 million to the EPA for EPA's 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 Ward Transformer site.

At December 31, 2004, and 2003, 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 many years, were:

(in millions)	**2004**	2003
Insurance fund	**$7**	$9
Transferred from NCNG at time of sale	**2**	2
Total accrual for environmental sites	**$9**	$11

PEC received insurance proceeds to address costs associated with environmental liabilities related to its involvement with some sites. All eligible expenses related to these are charged against a specific fund containing these proceeds. PEC spent approximately $2 million related to environmental remediation in 2004. PEC is unable to provide an estimate of the reasonably possible total remediation costs beyond what is currently accrued because investigations have not been completed at all sites.

This accrual has been recorded on an undiscounted basis. PEC measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. PEC will accrue costs for the sites to the extent its 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, PEC cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is anticipated that sufficient information will become available for several sites during 2005 to allow a reasonable estimate of PEC's obligation for those sites to be made.

PEF

At December 31, 2004, and 2003, PEF'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 many years, were:

(in millions)	**2004**	2003
Remediation of distribution and substation transformers	**$27**	$12
MGP and other sites	**18**	6
Total accrual for environmental sites	**$45**	$18

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. Through 2004 PEF has reviewed a number of distribution transformer sites and substation sites. PEF expects to have completed its review of distribution transformer sites by the end of 2007 and has completed the review of substation sites in 2004. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC clause. In 2004, PEF accrued an additional $19 million due to identification of additional sites requiring remediation, and spent approximately $4 million 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. In 2004, PEF received approximately $12 million in insurance claim settlement proceeds and recorded a related accrual for associated environmental expenses. The proceeds are restricted for use in addressing costs associated with environmental liabilities. Expenditures for the year were less than $1 million.

These accruals have been recorded on an undiscounted basis. PEF measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. This process often includes assessing and developing cost-sharing arrangements with other PRPs. 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 advanced to the stage where a reasonable estimate of

the remediation costs can be made, at this time PEF is unable to provide an estimate of its obligation to remediate these sites beyond what is currently accrued. As more activity occurs at these sites, PEF will assess the need to adjust the accruals. It is anticipated that sufficient information will become available in 2005 to make a reasonable estimate of PEF's obligation for one of the MGP sites.

The Florida Legislature passed risk-based corrective action (RBCA, known as Global RBCA) legislation in the 2003 regular session. 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 law 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. The FDEP developed the rules required by the RBCA statute, holding meetings with interested stakeholders and hosting public workshops. The rules have the potential for making future cleanups in Florida more costly to complete. The Global RBCA rule was adopted at the February 2, 2005, Environmental Review Commission hearing. The effective date of the Global RBCA rule is expected to be announced in April 2005. The Company and PEF are in the process of assessing the impact of this matter.

Florida Progress Corporation

In 2001, FPC established a $10 million accrual to address indemnities and retained an environmental liability associated with the sale of its Inland Marine Transportation business. In 2003, the accrual was reduced to $4 million based on a change in estimate. During 2004, expenditures related to this liability were not material to the Company's financial condition. As of December 31, 2004, the remaining accrual balance was approximately $3 million. FPC measures its liability for these exposures based on estimable and probable remediation scenarios.

Certain historical sites are being addressed voluntarily by FPC. An immaterial accrual has been established to address investigation expenses related to these sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

Rail

Rail Services is voluntarily addressing certain historical waste sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

Air Quality

Congress is considering legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs that could be material to the Company's consolidated financial position or results of operations. Control equipment that will be installed on North Carolina fossil generating facilities as part of the NC Clean Air legislation discussed below may address some of the issues outlined above. However, the Company cannot predict the outcome of this matter.

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 New Source Review requirements or New Source Performance Standards under the Clean Air Act. The Company was 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 other 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 cost through rate adjustments or similar mechanisms. The Company cannot predict the outcome of this matter.

In 2003, the EPA published a final rule addressing routine equipment replacement under the New Source Review program. The rule defines routine equipment replacement and the types of activities that are not subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The rule was challenged in the Federal Appeals Court and its implementation stayed. In July 2004, the EPA announced it will reconsider certain issues arising from the final routine equipment replacement rule. The comment period closed on August 30, 2004. The Company cannot predict the outcome of this matter.

In 1998, the EPA published a final rule under Section 110 of the Clean Air Act addressing the regional transport of ozone (NOx SIP Call). Total capital expenditures to meet the requirements of the NOx SIP Call Rule in North and South Carolina could reach approximately $370 million, which has not been adjusted for inflation. To date, the Company has spent approximately $282 million related to

these projected amounts. Increased operation and maintenance costs relating to the NOx SIP Call are not expected to be material to the Company's results of operations. Further controls are anticipated as electricity demand increases. Parties unrelated to the Company 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 Company cannot predict the outcome of this matter in Georgia.

In 1997, the EPA issued final regulations establishing a new 8-hour ozone standard. In April 2004, the EPA identified areas that do not meet the standard. The states with identified areas, including North and South Carolina, are proceeding with the implementation of the federal 8-hour ozone standard. Both states promulgated final regulations, which will require PEC to install NOx controls under the states' programs to comply with the 8-hour standard. The costs of those controls are included in the $370 million cost estimate above. However, further technical analysis and rulemaking may result in requirements for additional controls at some units. The Company cannot predict the outcome of this matter.

In June 2002, NC Clean Air legislation was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from coal-fired power plants. Progress Energy projects that its capital costs to meet these emission targets will total approximately $895 million by the end of 2013. PEC has expended approximately $108 million of these capital costs through December 31, 2004. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by this law. The law requires the emissions reductions to be completed in phases by 2013, and applies to each utility's total system rather than setting requirements for individual power plants. The law also freezes the utilities' base rates for five years 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 law requires PEC to amortize $569 million, representing 70% of the original cost estimate of $813 million, during the five-year rate freeze period. PEC recognized amortization of $174 million and $74 million for the years ended December 31, 2004, and 2003, respectively, and has recognized $248 million in cumulative amortization through December 31, 2004. The remaining amortization requirement of $321 million will be recorded over the three-year period ending December 31, 2007. The law 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 law, 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 law. The law also requires the State to undertake a study of mercury and carbon dioxide emissions in North Carolina. Operation and maintenance costs will increase due to the additional personnel, materials and general maintenance associated with the equipment. Operation and maintenance expenses are recoverable through base rates, rather than as part of this program. Progress Energy cannot predict the future regulatory interpretation, implementation or impact of this law.

In 1997, the EPA's Mercury Study Report and Utility Report to Congress concluded that mercury is not a risk to the average person in America and expressed uncertainty about whether reductions in mercury emissions from coal-fired power plants would reduce human exposure. Nevertheless, the EPA determined in 2000 that regulation of mercury emissions from coal-fired power plants was appropriate. In 2003, the EPA proposed alternative control plans that would limit mercury emissions from coal-fired power plants. The final rule was released on March 15, 2005. The EPA's rule establishes a mercury cap and trade program for coal-fired power plants that requires limits to be met in two phases, in 2010 and 2018. The Company is reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the mercury rule's requirements. Compliance plans, including the costs to the Company's operations, will be determined once the Company completes its review.

In conjunction with the proposed mercury rule, the EPA proposed a MACT standard to regulate nickel emissions from residual oil-fired units. The agency estimates the proposal will reduce national nickel emissions to approximately 103 tons. As proposed, the rule may require the Company to install additional pollution controls on its residual oil-fired units, resulting in significant capital expenditures. PEC does not have units impacted by this proposal; PEF has eight units that are affected, and they currently do not have pollution controls in place that would meet the proposed requirements of the nickel rule. The EPA expects to finalize the nickel rule in March 2005. Compliance costs will be determined following promulgation of the rule.

In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The final rule was released on March 10, 2005. The EPA's rule requires 28 states and the District of Columbia, including North Carolina, South Carolina, Georgia and Florida, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. The Company is reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the CAIR requirements. Compliance plans and cost to comply with the rule will be determined once the Company completes its review. The air quality controls already installed for compliance with the NOx SIP Call and currently planned by the Company to comply with the NC Clean Air legislation will reduce the costs required to meet the CAIR requirements for the Company's North Carolina units.

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. The EPA has agreed to make a determination on the petition by August 1, 2005. The Company cannot predict the outcome of this matter.

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 PEC and PEF in the immediate and extended future.

After many years of litigation and settlement negotiations, the EPA adopted regulations in February 2004 to implement Section 316(b) of the Clean Water Act. These regulations became effective September 7, 2004. The purpose of these regulations is to minimize adverse environmental impacts caused by cooling water intake structures and intake systems. Over the next several years these regulations will impact the larger base load generation facilities and may require the facilities to mitigate the effects to aquatic organisms by constructing intake modifications or undertaking other restorative activities. The Company currently estimates that from 2005 through 2009 the range of its expenditures to meet the Section 316(b) requirements of the Clean Water Act will be $85 million to $115 million. The range includes $20 million to $30 million at PEC and $65 million to $85 million at PEF.

Other Environmental Matters

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of carbon dioxide and other greenhouse gases. In 2004, Russia ratified the Protocol, and 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. A number of carbon dioxide emissions control proposals have been advanced in Congress. Reductions in carbon dioxide emissions to the levels specified by the Kyoto Protocol and some legislative proposals could be materially adverse to the Company's consolidated financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. The Company favors the voluntary program approach recommended by the administration and continually evaluates options for the reduction, avoidance and sequestration of greenhouse gases. However, the Company cannot predict the outcome of this matter.

Progress Energy has announced its plan to issue a report on the Company's activities associated with current and future environmental requirements. The report will include a discussion of the environmental requirements that the Company currently faces and expects to face in the future, as well as an assessment of potential mandatory constraints on carbon dioxide emissions. The report will be issued by March 31, 2006.

2. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2004, the following table reflects Progress Energy's contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions)	2005	2006	2007	2008	2009	Thereafter
Fuel	$2,219	$1,473	$663	$229	$252	$1,270
Purchased power	473	473	479	449	416	4,614
Construction obligations	51	–		–	–	–
Other purchase obligations	100	70	64	41	39	268
Total	$2,843	$2,016	$1,206	$719	$707	$6,152

FUEL AND PURCHASED POWER

FPC, PEC and Fuels have entered into various long-term contracts for coal, oil and gas. Payments under these commitments were $2,097 million, $1,719 million and $1,414 million for 2004, 2003 and 2002, respectively.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and the North Carolina Eastern Municipal Power Agency (Power Agency), PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, the Harris Plant. 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 the Harris Plant, 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 $38 million. These contractual purchases totaled $39 million, $36 million and $36 million for 2004, 2003 and 2002, respectively. In 1987, the NCUC ordered PEC to reflect the recovery of the capacity portion of these costs on a levelized basis over the original 15-year buyback period, thereby deferring for future recovery the difference between such costs and amounts collected through rates. In 1988, the SCPSC ordered similar treatment, but with a 10-year levelization period. At December 31, 2004, all previously deferred costs have been expensed.

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 $43 million, representing capital-related capacity costs. Estimated annual payments for energy and capacity costs are approximately $72 million through 2009. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $63 million, $66 million and $59 million for 2004, 2003 and 2002, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility. 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 300 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 $42 million, $37 million and $38 million in 2004, 2003 and 2002 respectively.

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 $129 million, $124 million and $109 million for 2004, 2003 and 2002, respectively. Total capacity payments were $56 million, $55 million and $50 million for 2004, 2003 and 2002, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, at December 31, 2004, are $60 million, $63 million, $65 million, $66 million and $67 million for 2005 through 2009, respectively, and $244 million thereafter.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (qualifying facilities) with expiration dates ranging from 2005 to 2025. These purchased power contracts generally provide for capacity and energy payments. Energy payments for the PEF contracts are based on actual power taken under these contracts. Capacity payments are subject to the qualifying facilities (QFs) meeting certain contract performance obligations. PEF's total capacity purchases under these contracts amounted to $248 million, $244 million and $235 million for 2004, 2003 and 2002, respectively. Minimum expected future capacity payments under these contracts at December 31, 2004, are $271 million, $279 million, $289 million, $298 million and $263 million for 2005 through 2009, respectively, and $3.8 billion thereafter. PEC has various pay-for-performance contracts with QFs for approximately 400 MW of capacity expiring at various times through 2009. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $91 million in 2004, $113 million in 2003 and $145 million in 2002.

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 $3.3 billion. The transactions

are subject to several conditions precedent, which include obtaining the Florida Public Service Commission'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 precedent in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

The Company has purchase obligations related to various capital construction projects. Total payments under these contracts were $102 million, $158 million and $143 million for 2004, 2003 and 2002, respectively.

OTHER PURCHASE OBLIGATIONS

The Company has entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, a PVI parts and services contract, and a PEF service agreement related to the Hines Energy Complex. Payments under these agreements were $69 million, $31 million and $420 million for 2004, 2003 and 2002, respectively.

On December 31, 2002, PEC and PVI entered into a contractual commitment to purchase at least $13 million and $4 million, respectively, of capital parts by December 31, 2010. During 2004 and 2003, no capital parts have been purchased under this contract.

B. Other Commitments

The Company has 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. The Company 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 $73 million and $94 million at December 31, 2004 and 2003, respectively, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2004 and 2003, 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. Actual amounts paid under these agreements were none in 2004, $2 million in 2003 and $51 million in 2002. Future expected minimum royalty payments are approximately $26 million for 2005 through 2007. The Company has the right in the related agreements and their amendments that allow the Company to escrow those payments if certain conditions in the agreements are met. The Company has exercised that right and retained 2004 and 2003 royalty payments of approximately $42 million and $48 million, respectively, pending the establishment of the necessary escrow accounts. Once established, those funds will be placed into escrow.

During 2004 Progress Energy made the first installment of $10 million for a contract dispute. The installments for 2005 and 2006, respectively, are $16 million and $17 million (See Note 20).

C. Leases

The Company leases 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. Rent expense under operating leases totaled $65 million, $60 million and $71 million for 2004, 2003 and 2002, respectively. Purchased power expense under agreements classified as operating leases were approximately $24 million in 2004 and $5 million in 2003.

Assets recorded under capital leases at December 31 consist of:

(in millions)	**2004**	2003
Buildings	**$30**	$30
Equipment and other	**2**	3
Less: Accumulated amortization	**(11)**	(10)
	$21	$23

Minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable leases at December 31, 2004, are:

(in millions)	Capital Leases	Operating Leases
2005	$4	$66
2006	4	55
2007	4	58
2008	4	58
2009	3	54
Thereafter	31	307
	$50	$598
Less amount representing imputed interest	(21)	
Present value of net minimum lease payments under capital leases	$29	

In 2003, the Company 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.

The Company, excluding PEC and PEF, is also a lessor of land, buildings and other types of properties it owns 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 2005 through 2009 are approximately $32 million, $22 million, $14 million, $9 million and $6 million, respectively, with $17 million receivable thereafter. Rents received under these operating leases totaled $63 million, $46 million and $53 million for 2004, 2003 and 2002, respectively.

PEC is the lessor of electric poles, streetlights and other facilities. Minimum rentals under noncancelable leases are $9 million for 2005 and none thereafter. Rents received totaled $32 million, $31 million and $28 million for 2004, 2003 and 2002, respectively.

PEF is the lessor of electric poles, streetlights and other facilities. Rents received are based on a fixed minimum rental where price varies by type of equipment and totaled $63 million, $56 million and $52 million for 2004, 2003 and 2002, respectively. Minimum rentals receivable (excluding streetlights) under noncancelable leases for 2005 is $5 million, for 2006 through 2009 $1 million, and $8 million thereafter. Streetlight rentals were $40 million, $38 million and $34 million for 2004, 2003 and 2002 respectively. Future streetlight rentals would approximate 2004 revenues.

D. Guarantees

To facilitate commercial transactions of the Company's subsidiaries, Progress Energy and certain wholly owned subsidiaries enter into agreements providing future financial or performance assurances to third parties (See Note 19).

At December 31, 2004, the Company had issued guarantees on behalf of third parties with an estimated maximum exposure of approximately $10 million. These guarantees support synthetic fuel operations. At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements.

In connection with the sale of partnership interests in Colona (See Note 4B), Progress Fuels indemnified the buyers against any claims related to Colona resulting from violations of any environmental laws. Although the terms of the agreement provide for no limitation to the maximum potential future payments under the indemnification, the Company has estimated that the maximum total of such payments would not be material.

Claims and Uncertainties

OTHER CONTINGENCIES

1. Pursuant to the Nuclear Waste Policy Act of 1982, the predecessors to PEF and PEC entered into contracts with the U.S. Department of Energy (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.

DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, PEC and PEF 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 (SNF) by failing to accept SNF from various Progress Energy facilities on or before January 31, 1998. Damages due to DOE's breach will likely exceed $100 million. Approximately 60 cases involving the Government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

DOE and the PEC/PEF parties 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 SNF and high level waste (HLW) by which the Government was contractually obligated to accept contract holders' SNF and/or HLW, 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 that are currently scheduled to occur during 2005. Resolution of these issues in other cases could facilitate agreements by the parties in the PEC/PEF lawsuit, or at a minimum, inform the Court of decisions reached by other courts if they remain contested and require resolution in this case. The trial court has continued this stay until June 24, 2005.

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, Crystal River Unit No. 3 (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.

In July 2002, Congress passed an override resolution to Nevada's veto of DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nevada. In January 2003, the State of Nevada, Clark County, Nevada, and the City of 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 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. EPA is currently reworking the standard but has not stated when the work will be complete. 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, DOE announced it would not submit the license application until mid-2005 or later. Also in November 2004, Congressional negotiators approved $577 million for fiscal year 2005 for the Yucca Mountain project, approximately $300 million less than requested by DOE but approximately the same as approved in 2004. The DOE continues to state it plans to begin operation of the repository at Yucca Mountain in 2010. PEC and PEF cannot predict the outcome of this matter.

2. In 2001, PEC entered into a contract to purchase coal from Dynegy Marketing and Trade (DMT). After DMT experienced financial difficulties, including credit ratings downgrades by certain credit reporting agencies, PEC requested credit enhancements in accordance with the terms of the coal purchase agreement in July 2002. When DMT did not offer credit enhancements, as required by a provision in the contract, PEC terminated the contract in July 2002. PEC initiated a lawsuit seeking a declaratory judgment that the termination was lawful. DMT counterclaimed, stating the termination was a breach of contract and an unfair and deceptive trade practice. On March 23, 2004, the United States District Court for the Eastern District of North Carolina ruled that PEC was liable for breach of contract, but ruled against DMT on its unfair and deceptive trade practices claim. On April 6, 2004, the Court entered a judgment against PEC in the amount of approximately $10 million. The Court did not rule on DMT's request under the contract for pending legal costs.

On May 4, 2004, PEC authorized its outside counsel to file a notice of appeal of the April 6, 2004, judgment, and on May 7, 2004, the notice of appeal was filed with the United States Court of Appeals for the Fourth Circuit. On June 8, 2004, DMT filed a motion to dismiss the appeal on the ground that PEC's notice of appeal should have been filed on or before May 6, 2004. On June 16, 2004, PEC filed a motion with the trial court requesting an extension of the deadline for the filing of the notice of appeal. By order dated September 10, 2004, the trial court denied the extension request. On September 15, 2004, PEC filed a notice of appeal of the September 10, 2004, order, and by order dated September 29, 2004, the appellate court consolidated the first and second appeals. DMT's motion to dismiss the first appeal remains pending.

The consolidated appeal has been fully briefed, and the court of appeals has indicated that it will hear arguments which tentatively have been scheduled for the week of May 23, 2005.

In the first quarter of 2004, PEC recorded a liability for the judgment of approximately $10 million and a regulatory asset for the probable recovery through its fuel adjustment clause in the first quarter of 2004. The Company cannot predict the outcome of this matter.

3. On February 1, 2002, the Company filed a complaint with the Surface Transportation Board (STB) challenging the rates charged by Norfolk Southern Railway Company (Norfolk Southern) for coal transportation to certain generating plants. In a decision dated December 23, 2003, the STB found that the rates were unreasonable, awarded reparations and prescribed maximum rates. Both parties petitioned the STB for reconsideration of the December 23, 2003 decision. On October 20, 2004, the STB reconsidered its December 23, 2003 decision and concluded that the rates charged by Norfolk Southern were not unreasonable. Because the Company paid the maximum rates prescribed by the STB in its December 23, 2003 decision for several months during 2004, which were

less than the rates ultimately found to be reasonable, the STB ordered the Company to pay to Norfolk Southern the difference between the rate levels plus interest.

The Company subsequently filed a petition with the STB to phase in the new rates over a period of time, and filed a notice of appeal with the U.S. Court of Appeals for the D.C. Circuit. Pursuant to an order issued by the STB on January 6, 2005, the phasing proceeding will proceed on a schedule that appears likely to produce an STB decision before the end of 2005. On January 12, 2005, the STB filed a Motion to Dismiss the Company's appeal on the grounds that its October 20, 2004, order is not "final" until the Company's phasing application has been decided.

As of December 31, 2004, the Company has accrued a liability of $42 million, of which $23 million represents reparations previously remitted to PEC by Norfolk Southern that are now subject to refund. Of the remaining $19 million, $17 million has been recorded as deferred fuel cost on the Consolidated Balance Sheet, while the remaining $2 million attributable to wholesale customers has been charged to fuel used in electric generation on the Consolidated Statements of Income.

The Company cannot predict the outcome of this matter

4. The Company, through its subsidiaries, is a majority owner in five entities and a minority owner in one entity that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). The production and sale of the synthetic fuel from these facilities qualify for tax credits under Section 29 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 amount of Section 29 credits that the Company is allowed to claim in any calendar year is limited by the amount of the Company's regular federal income tax liability. Synthetic fuel tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. All entities have received PLRs from the IRS with respect to their synthetic fuel operations. However, these PLRs do not address the placed-in-service date determination. The PLRs do not limit the production on which synthetic fuel credits may be claimed. Total Section 29 credits generated to date (including those generated by FPC prior to its acquisition by the Company) are approximately $1.5 billion, of which $713 million has been used to offset regular federal income tax liability and $745 million is being carried forward as deferred alternative minimum tax credits. Also, $7 million has not been recognized due to the decrease in tax liability resulting from expenses incurred for the 2004 hurricane damage. The current Section 29 tax credit program expires at the end of 2007.

IMPACT OF HURRICANES

For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 8.3 million tons of synthetic fuel and the Company recorded $215 million of Section 29 tax credits. The amount of synthetic fuel sold and tax credits recorded in 2004 was impacted by hurricane costs that reduced the Company's projected 2004 regular tax liability.

For the nine months ended September 30, 2004, the Company's synthetic fuel facilities sold 7.7 million tons of synthetic fuel, which generated an estimated $204 million of Section 29 tax credits. Due to the anticipated decrease in the Company's tax liability as a result of expenses incurred for the 2004 hurricane damage, the Company estimated that it would be able to use in 2004, or carry forward to future years, only $125 million of these Section 29 tax credits at September 30, 2004. As a result, the Company recorded a charge of $79 million related to Section 29 tax credits at September 30, 2004.

On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from customers over a two-year period. Based on a reasonable expectation at December 31, 2004, that the FPSC will grant the requested recovery of the storm costs, the Company's loss from the casualty is less than originally anticipated. As of December 31, 2004, the Company estimates that it will be able to use in 2004, or carry forward to future years, $215 million of these Section 29 tax credits. Therefore, the Company recorded tax credits of $90 million for the quarter ended December 31, 2004, which the Company now anticipates can be used. For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 8.3 million tons of synthetic fuel, which generated an estimated $222 million of Section 29 tax credits. As of December 31, 2004, the Company anticipates that approximately $7 million of tax credits related to synthetic fuel sold during the year could not be used and have not been recognized.

The Company believes its right to recover storm costs is well established; however, the Company cannot predict the timing or outcome of this matter. If the FPSC should deny PEF's petition for the recovery of storm costs in 2005, there could be a material impact on the amount of 2005 synthetic fuels production and results of operations.

IRS PROCEEDINGS

In September 2002, all of Progress Energy's majority-owned synthetic fuel entities were accepted into the IRS's Pre-Filing Agreement (PFA) program. The PFA program allows taxpayers to voluntarily accelerate the IRS exam process in order to seek resolution of specific issues.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the IRS concerning their Colona synthetic fuel facilities. The Colona Closing Agreement provided that the Colona facilities were placed in service before July 1, 1998, which is one of the qualification requirements for tax credits under Section 29. The Colona Closing Agreement further provides that the fuel produced by the Colona facilities in 2001 is a "qualified fuel" for purposes of the Section 29 tax credits. This action concluded the PFA program with respect to Colona.

In July 2004, Progress Energy was notified that the IRS field auditors anticipated taking an adverse position regarding the placed-in-service date of the Company's four Earthco synthetic fuel facilities. Due to the auditors' position, the IRS decided to exercise its right to withdraw from the PFA program with Progress Energy. With the IRS's withdrawal from the PFA program, the review of Progress Energy's Earthco facilities is back on the normal procedural audit path of the Company's tax returns. Through December 31, 2004, the Company, on a consolidated basis, has used or carried forward approximately $1.0 billion of tax credits generated by Earthco facilities. If these credits were disallowed, the Company's one-time exposure for cash tax payments would be $294 million (excluding interest), and earnings and equity would be reduced by approximately $1.0 billion, excluding interest. Progress Energy's amended $1.13 billion credit facility includes a covenant that limits the maximum debt-to-total capital ratio to 68%. This ratio includes other forms of indebtedness such as guarantees issued by PGN, letters of credit and capital leases. As of December 31, 2004, the Company's debt-to-total capital ratio was 60.7% based on the credit agreement definition for this ratio. The impact on this ratio of reversing approximately $1.0 billion of tax credits and paying $294 million for taxes would be to increase the ratio to 65.7%.

On October 29, 2004, Progress Energy received the IRS field auditors' report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and that the tax credits generated by those facilities should be disallowed. The Company disagrees with the field audit team's factual findings and believes that the Earthco facilities were placed in service before July 1, 1998. The Company also believes that the report applies an inappropriate legal standard concerning what constitutes "placed in service." The Company intends to contest the field auditors' findings and their proposed disallowance of the tax credits.

Because of the disagreement between the Company and the field auditors as to the proper legal standard to apply, the Company believes that it is appropriate and helpful to have this issue reviewed by the National Office of the IRS, just as the National Office reviewed the issues involving chemical change. Therefore, the Company is asking the National Office to clarify the legal standard and has initiated this process with the National Office. The Company believes that the appeals process, including proceedings before the National Office, could take up to two years to complete; however, it cannot control the actual timing of resolution and cannot predict the outcome of this matter.

In management's opinion, the Company is complying with all the necessary requirements to be allowed such credits under Section 29, and, although it cannot provide certainty, it believes that it will prevail in these matters. Accordingly, while the Company adjusted its synthetic fuel production for 2004 in response to the effects of expenses incurred due to the hurricane damage and its impact on 2004 tax liability, it has no current plans to alter its synthetic fuel production schedule for future years as a result of the IRS field auditors' report. However, should the Company fail to prevail in these matters, there could be material liability for previously taken Section 29 tax credits, with a material adverse impact on earnings and cash flows.

PROPOSED ACCOUNTING RULES FOR UNCERTAIN TAX POSITIONS

In July 2004, the FASB stated that it plans to issue 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 FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits.

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 the Company's synthetic fuel operations. Progress Energy is providing information in connection with this investigation. The Company cannot predict the outcome of this matter.

SALE OF PARTNERSHIP INTEREST

In June 2004, the Company, through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 Company's book value of the interests sold totaled approximately $5 million. The company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007 and approximately $8 million through the second quarter of 2008. 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.

IMPACT OF CRUDE OIL PRICES

Although the Internal Revenue Code Section 29 tax credit program is expected to continue through 2007, recent unprecedented and unanticipated increases in the price of oil could limit the amount of those credits or eliminate them altogether for one or more of the years following 2004. 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 value (the "Threshold Price"), the amount of 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 tax credits are eliminated for that year. For 2003, the Threshold Price was $50.14 per barrel and the Phase Out Price was $62.94 per barrel. The Threshold Price and the Phase Out Price are adjusted annually for inflation.

If the Annual Average Price falls between the Threshold Price and the Phase Out Price for a year, the amount by which Section 29 tax credits are reduced will depend on where the Average Annual Price falls in that continuum. For example, for 2003, if the Annual Average Price had been $56.54 per barrel, there would have been a 50% 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 its calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2003 was published in April 2004.

Although the official notice for 2004 is not expected to be published until April 2005, the Company does not believe that the Annual Average Price for 2004 will reach the Threshold Price for 2004. Consequently, the Company does not expect the amount of its 2004 Section 29 tax credits to be adversely affected by oil prices.

The Company cannot predict with any certainty the Annual Average Price for 2005 or beyond. Therefore, it cannot predict whether the price of oil will have a material effect on its synthetic fuel business after 2004. However, if during 2005 through 2007, oil prices remain at historically high levels or increase, the Company's synthetic fuel business may be adversely affected for those years, and, depending on the magnitude of such increases in oil prices, the adverse affect for those years could be material and could have an impact on the Company's synthetic fuel results of operations and production plans.

5. The Company and its subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, accruals and disclosures have been made in accordance with SFAS No. 5, "Accounting for Contingencies," to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on the Company's consolidated results of operations or financial position.

24. SUBSEQUENT EVENTS

Sale of Progress Rail

On February 18, 2005, the Company announced it has entered into a definitive agreement to sell Progress Rail to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Gross cash proceeds from the transaction will be $405 million, subject to working capital adjustments. The sale is expected to close by mid-2005, and is subject to various closing conditions customary to such transactions. Proceeds from the sale are expected to be used to reduce debt. The Company expects to report Progress Rail as a discontinued operation in the first quarter of 2005. The carrying amounts for the assets and liabilities of the discontinued operations disposal group included in the Consolidated Balance Sheets as of December 31, are as follows:

(in millions)	**2004**	2003
Total current assets	**$378**	$373
Total property, plant & equipment (net)	**173**	151
Total other assets	**40**	77
Total current liabilities	**156**	114
Total long-term liabilities	**3**	3
Total capitalization	**432**	484

Cost-Management Initiative

On February 28, 2005, as part of a previously announced cost-management initiative, the executive officers of the Company approved a workforce restructuring. The restructuring will result in a reduction of approximately 450 positions and is expected to be completed in September 2005. The cost-management initiative is designed to permanently reduce by $75 million to $100 million the projected growth in the Company's annual operation and maintenance expenses by the end of 2007. In addition to the workforce restructuring, the cost-management initiative includes a voluntary enhanced retirement program.

In connection with the cost-management initiative, the Company expects to incur one-time pre-tax charges of approximately $130 million. Approximately $30 million of that amount relates to payments for severance benefits, and will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $100 million will be recognized in the second quarter of 2005 and relates primarily to postretirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program. Approximately 3,500 of the Company's 15,700 employees are eligible to participate in the voluntary enhanced retirement program. The total cost-management initiative charges could change significantly depending upon how many eligible employees elect early retirement under the voluntary enhanced retirement program and the salary, service years and age of such employees.

CONSOLIDATED QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data is as follows:

(in millions except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2004				
Operating revenues	**$2,245**	**$2,408**	**$2,761**	**$2,358**
Operating income	**296**	**305**	**584**	**291**
Income from continuing operations before cumulative effect of changes in accounting principles	**108**	**153**	**303**	**189**
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	**0.45**	**0.63**	**1.25**	**0.78**
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	**0.45**	**0.63**	**1.24**	**0.78**
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**
Year ended December 31, 2003				
Operating revenues	$2,187	$2,050	$2,457	$2,047
Operating income	357	274	478	248
Income from continuing operations before cumulative effect of changes in accounting principles	207	154	337	113
Net income	219	157	318	88
Common stock data:				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.89	0.65	1.41	0.47
Net income	0.94	0.66	1.33	0.37
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.89	0.65	1.39	0.47
Net income	0.94	0.66	1.31	0.37
Dividends declared per common share	0.560	0.560	0.560	0.575
Market price per share – High	46.10	48.00	45.15	46.00
– Low	37.45	38.99	39.60	41.60

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. The 2003 amounts were restated for the cessation of reporting results for portions of the Fuels' segment operations one month in arrears (See Note 1B) and for discontinued operations (See Note 4C). Fourth quarter 2004 includes a $31 million after-tax gain on sale of natural gas assets (See Note 4A) and $90 million of Section 29 tax credits being recorded (See Note 23E). Third quarter 2004 includes reversal of $79 million of Section 29 tax credits (See Note 23E). Second quarter 2004 includes the settlement of a civil proceeding related to SRS of $43 million ($29 million after-tax). Fourth quarter 2003 includes impairments related to Kentucky May and Affordable Housing investment of $38 million ($24 million after-tax) (See Note 10). Fourth quarter 2003 includes a cumulative effect for DIG Issue 20 of $38 million ($23 million after-tax) (See Note 18).

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

(in millions except per share data)	**2004**	2003	2002	2001	2000
Results of Operations[a]					
Operating revenues	**$9,772**	$8,741	$8,091	$8,129	$3,769
Net income from continuing operations before cumulative effect	**753**	811	552	541	478
Net income	**$759**	$782	$528	$542	$478
Balance Sheet Data at Year-end					
Total assets[b]	**$25,993**	$26,093	$24,272	$23,701	$22,875
Capitalization:					
Common stock equity	**$7,633**	$7,444	$6,677	$6,004	$5,424
Preferred stock-redemption not required	**93**	93	93	93	93
Minority interest	**36**	30	18	12	–
Long-term debt, net[c]	**9,521**	9,934	9,747	8,619	4,904
Current portion of long-term debt	**349**	868	275	688	184
Short-term obligations	**684**	4	695	942	4,959
Total Capitalization and Total Debt	**$18,316**	$18,373	$17,505	$16,358	$15,564
Other Financial Data					
Return on average common stock equity (percent)	**9.99**	11.07	8.44	9.41	13.04
Ratio of earnings to fixed charges	**2.26**	1.97	1.48	1.52	3.36
Number of common shareholders of record	**67,638**	70,159	72,792	75,673	80,289
Book value per common share	**$31.26**	$30.94	$28.73	$28.20	$27.17
Basic earnings per common share					
Income from continuing operations	**$3.11**	$3.42	$2.54	$2.64	$3.04
Net income	**$3.13**	$3.30	$2.43	$2.65	$3.04
Diluted earnings per common share					
Income from continuing operations	**$3.10**	$3.40	$2.53	$2.63	$3.03
Net income	**$3.12**	$3.28	$2.42	$2.64	$3.03
Dividends declared per common share	**$2.32**	$2.26	$2.20	$2.14	$2.08
Energy Supply – Electric Utility (millions of kWh)[a]					
Generated					
Steam	**50,782**	51,501	49,734	48,732	31,132
Nuclear	**30,445**	30,576	30,126	27,301	23,857
Hydro	**802**	955	491	245	441
Combustion turbines/combined cycle	**9,695**	7,819	8,522	6,644	1,337
Purchased	**13,466**	13,848	14,305	14,469	5,724
Total energy, supply (Company share)	**105,190**	104,699	103,178	97,391	62,491
Joint-owner share[d]	**5,395**	5,213	5,258	4,886	4,505
Total System Energy Supply	**110,585**	109,912	108,436	102,277	66,996

[a] Results of operations and energy supply data includes information for Florida Progress Corporation since November 30, 2000, the date of acquisition.
[b] All periods have been restated for the reclassification of cost at removal.
[c] Includes long-term debt to affiliated trust of $270 million at December 31, 2004, and 2003.
[d] Amounts are net of Company's purchases from joint-owners.

RECONCILIATION OF ONGOING EARNINGS PER SHARE TO REPORTED GAAP EARNINGS PER SHARE (UNAUDITED)

Progress Energy's management uses ongoing earnings per share to evaluate the operations of the Company and to establish goals for management and employees. Management believes this presentation is appropriate and enables investors to compare more accurately the Company's 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	**2004**	2003	2002
Ongoing earnings per share	**$3.06**	$3.56	$3.81
Contingent value obligation mark-to-market	**0.04**	(0.04)	0.13
NCNG discontinued operations	**0.02**	(0.03)	(0.11)
SRS litigation settlement	**(0.12)**	–	–
Gain on sale of natural gas assets	**0.13**	–	–
Cumulative effect of accounting changes	–	(0.09)	–
Impairments and one-time charges	–	(0.10)	(1.22)
Ice storm impact	–	–	(0.08)
PEF retroactive revenue refund	–	–	(0.10)
Reported GAAP earnings per share	**$3.13**	$3.30	$2.43

Contingent Value Obligation (CVO) Mark-to-Market

In connection with the acquisition of Florida Progress Corporation, Progress Energy issued 98.6 million CVOs. Each CVO represents the right 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 the Company's underlying obligation, management does not consider the adjustment a component of ongoing earnings.

NCNG Discontinued Operations

The operations of NCNG are reported as discontinued operations due to its sale, and therefore management does not believe this activity is representative of the ongoing operations of the Company.

SRS Litigation Settlement

In June 2004, SRS, a subsidiary of the Company, reached and recorded a charge for a settlement agreement in a civil suit. Management does not believe this settlement charge is indicative of the ongoing operations of the Company.

Gain on Sale of Natural Gas Assets

In December 2004, the Company finalized the sale of certain gas-producing properties and related assets and recognized a gain. Management does not believe this gain is representative of the ongoing operations of the Company.

Cumulative Effect of Accounting Changes

Progress Energy recorded the cumulative effect of changes in accounting principles due to the adoption of new FASB accounting guidance. The impact to Progress Energy was due primarily to the new FASB guidance related to the accounting for certain contracts. Due to the nonrecurring nature of the adjustment, management believes it is not representative of the 2003 operations of the Company.

Impairments and One-Time Charges

During 2003, the Company recorded after-tax impairments of its Affordable Housing portfolio and certain assets at the Kentucky May coal company. During 2002, the Company committed to a divestiture plan for Railcar, Ltd., and recorded an estimated loss on assets held for sale. During 2002, the Company also recorded an after-tax impairment and one-time charge of Progress Telecom's and Caronet's assets. Progress Energy also wrote off the remaining amount of its investment in Interpath. Management does not believe these impairments and one-time charges are representative of the ongoing operations of the Company.

Ice Storm Impact

During 2002, the Company experienced a severe ice storm in the Carolinas that caused extensive damage to the distribution system. Due to the extensive costs associated with the storm damage, management believes the restoration costs are not representative of the 2002 ongoing operations of Progress Energy Carolinas.

PEF Retroactive Revenue Refund

The one-time retroactive rate refund under the Progress Energy Florida rate settlement in March 2002 was related to funds collected during the period between March 13, 2001, when the prior rate agreement in Florida expired, and March 27, 2002, the date the parties entered into the settlement agreement. Due to the nonrecurring nature of the refund, management believes it is not representative of the 2002 operations of Progress Energy Florida.

Shareholder Information

Notice of Annual Meeting

Progress Energy's 2005 annual meeting of shareholders will be held on May 11, 2005, at 10 a.m. at the Hilton St. Petersburg, in St. Petersburg, Fla. 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 EquiServe 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, stock transfer information and the option to speak with a shareholder services representative. Call toll-free **1.866.290.4388**.

You may direct other questions concerning stock ownership to Progress Energy's Shareholder Relations via e-mail at shareholder.relations@pgnmail.com or by writing to the following address:

Progress Energy, Inc.
Shareholder Relations
P.O. Box 1551
Raleigh, NC 27602-1551

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 our transfer agent at the above address or call them toll-free at **1.866.290.4388**.

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. To obtain online access to your shareholder account, go to **equiserve.com**. 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, EquiServe, 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 **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.

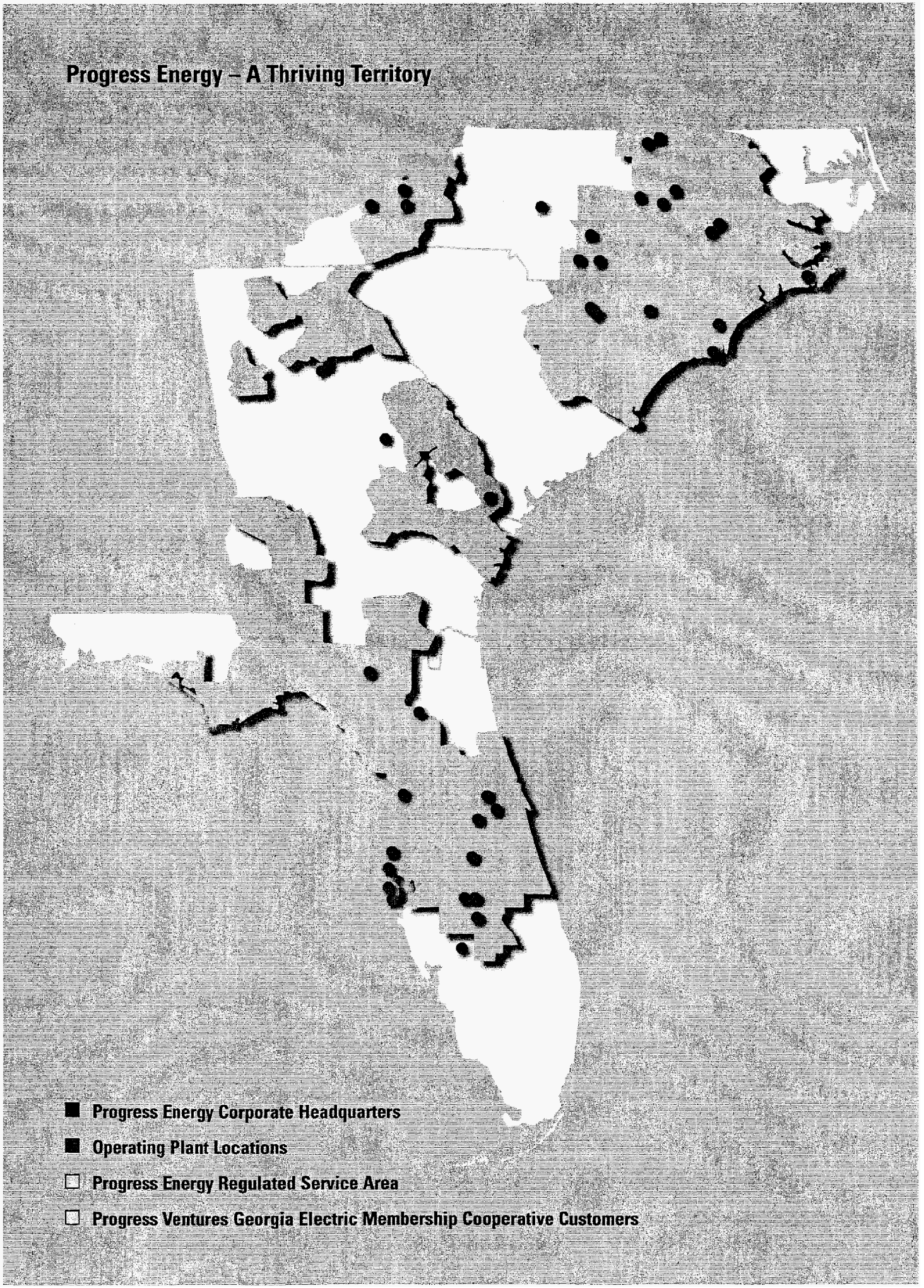
This annual report is submitted for shareholders' information. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

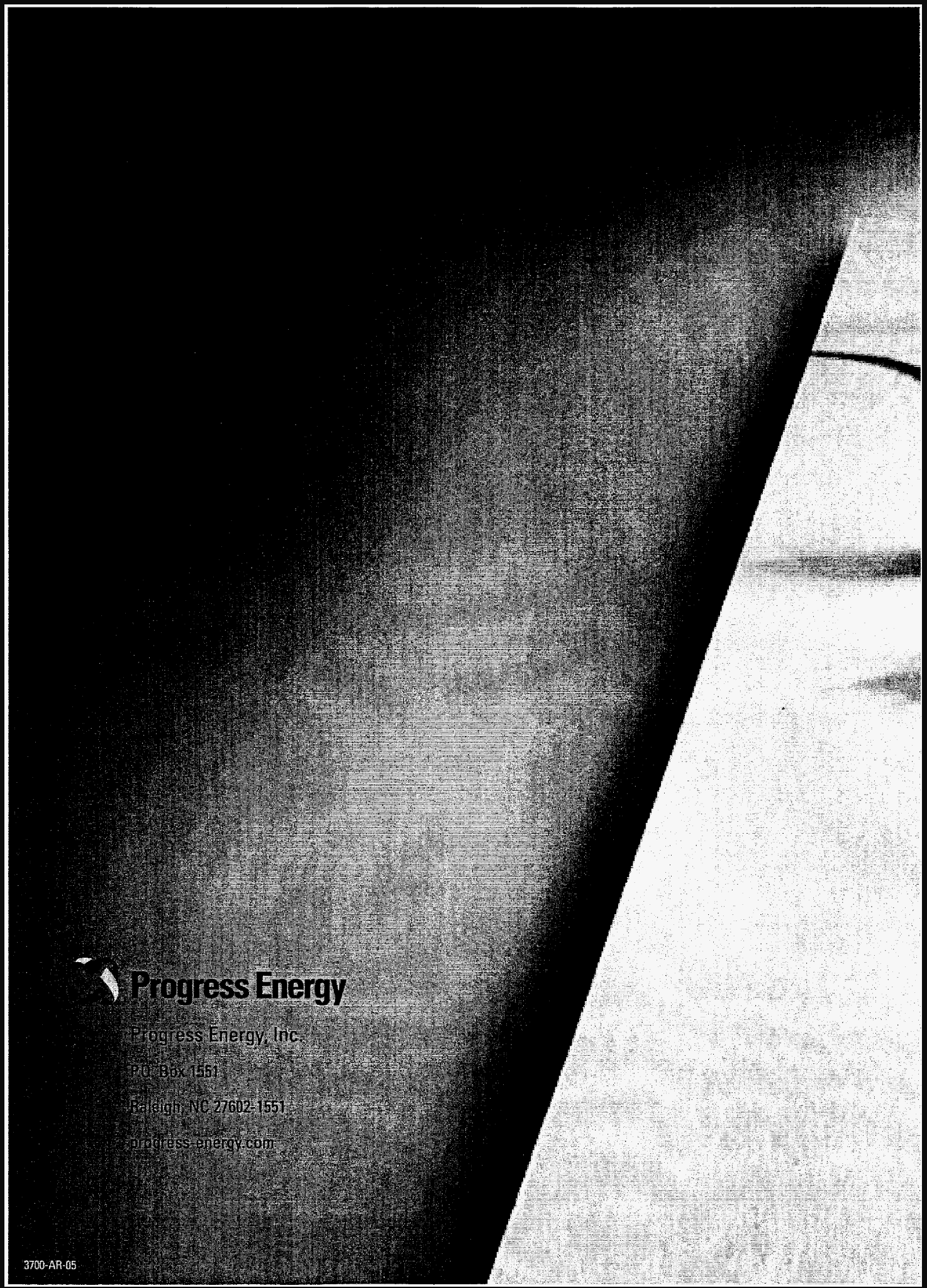
NYSE Certifications

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, 2004. 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.

©2005 Progress Energy, Inc. SCC-112-05 03/05

Progress Energy – A Thriving Territory





Progress Energy

Progress Energy, Inc.
P.O. Box 1551
Raleigh, NC 27602-1551
progress-energy.com

3700-AR-05

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: Provide a copy of the most recent Form 10-K annual report to the Securities and Exchange Commission and all Form 10-Q quarterly reports filed subsequent to the filing of the latest 10-K.

Type of data shown:

Projected Test Year Ended 12/31/2006
xx Prior Year Ended 12/31/2005
xx Historical Year 12/31/2004
Witness: Bazemore

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1											
2											
3	Attached is the 2003 Form 10-K and 2004 Form 10-Qs to the Securities and Exchange Commission.										
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
23											
24											
25											
26											
27											

Supporting Schedules:

Recap Schedules:

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from_____to_____

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number	I.R.S. Employer Identification Number
1-8349	**Florida Progress Corporation** 410 South Wilmington Street Raleigh, North Carolina 27601 Telephone (919) 546-6111 State of Incorporation: Florida	59-2147112
1-3274	**Florida Power Corporation** **d/b/a Progress Energy Florida, Inc.** 100 Central Avenue St. Petersburg, Florida 33701 Telephone (727) 820-5151 State of Incorporation: Florida	59-0247770

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT

Title of each class	Name of each exchange on which registered
Florida Progress Corporation: 7.10% Cumulative Quarterly Income Preferred Securities, Series A, of FPC Capital I (and the Guarantee of Florida Progress with respect thereto)	New York Stock Exchange
Progress Energy Florida, Inc.:	None

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Florida Progress Corporation: None
Florida Power Corporation: None

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. **[X]**

Indicate by check mark whether the registrants are accelerated filers (as defined in Rule 12b-2 of the Act).
YES [ ] NO [X]

As of June 30, 2004, the aggregate market value of the voting and non-voting common equity of each of the registrants held by non-affiliates was $0. All of the common stock of Florida Progress Corporation is owned by Progress Energy, Inc., its corporate parent. All of the common stock of Florida Power Corporation is owned by Florida Progress Corporation.

As of February 2005, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Florida Progress Corporation	Common Stock (without par value)	98,616,658
Florida Power Corporation	Common Stock (without par value)	100

Florida Progress Corporation and Florida Power Corporation meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format permitted by General Instruction I(2) to such Form 10-K.

This combined Form 10-K is filed separately by two registrants: Florida Progress Corporation and Florida Power Corporation. Information contained herein relating to either individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrant.

TABLE OF CONTENTS

GLOSSARY

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

PART I

ITEM 1. BUSINESS

ITEM 2. PROPERTIES

ITEM 3. LEGAL PROCEEDINGS

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

PART II

ITEM 5. MARKET FOR THE REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

ITEM 6. SELECTED FINANCIAL DATA

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

ITEM 9A. CONTROLS AND PROCEDURES

ITEM 9B. OTHER INFORMATION

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

RISK FACTORS

GLOSSARY OF TERMS

The following abbreviations or acronyms used in the text of this combined FORM 10-K are defined below:

TERM	DEFINITION
AFUDC	Allowance for funds used during construction
the Agreement	Stipulation and Settlement Agreement related to retail rate matters
ARO	Asset retirement obligation
AST	Advanced Separation Technology
Bcf	Billion cubic feet
Btu	British thermal units
CAIR	Clean Air Interstate Rule
Calgon	Calgon Carbon Corporation
Caronet	Caronet, Inc.
the Code	Internal Revenue Code
Colona	Colona Synfuel Limited Partnership, L.L.L.P.
the Company, Florida Progress or FPC	Florida Progress Corporation
CP&L Energy	CP&L Energy, Inc.
CR3	PEF's nuclear generating plant, Crystal River Unit No. 3
DD&A	Depreciation, depletion and amortization
DOE	United States Department of Energy
ECRC	Environmental Cost Recovery Clause
Electric Fuels	Electric Fuels Corporation
EPA	United States Environmental Protection Agency
EPIK	EPIK Communications, Inc.
ESOP	Employee stock ownership plan
ETS	Engineering & Track-work Services
FASB	Financial Accounting Standards Board
FASB Staff Position 106-2	Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FIN No. 46R	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51"
Financial Statements	Florida Progress' Financial Statements and Progress Energy Florida's Financial Statements contained under ITEM 8 herein
Florida Power or the Utility	Florida Power Corporation d/b/a Progress Energy Florida, Inc.
FPSC	Florida Public Service Commission
Funding Corp.	Florida Progress' Funding Corporation
GAAP	Accounting principles generally accepted in the United States of America
Georgia Power	Georgia Power Company
Global	U.S. Global LLC
HLW	High Level Waste
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
kVA	Kilovolt-ampere
LRS	Locomotive and Railcar Services
LTIP	Long-Term Incentive Plan
MAC	Material adverse change
MACT	Maximum Achievable Control Technology
Mcfe	Million cubic feet equivalents
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured Gas Plant
MW	Megawatts
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Council
NOx	Nitrogen Oxide
NRC	United States Nuclear Regulatory Commission

NSP	Northern States Power
OCI	Other comprehensive income
Odyssey	Odyssey Telecorp, Inc.
OPEB	Other postretirement benefits
P11	PEF's Intercession City Unit P11
PEF or the Utility	Progress Energy Florida, Inc., formerly referred to as Florida Power Corporation
PESC	Progress Energy Service Company, LLC
PFA	IRS Prefiling Agreement
The Plan	Revenue Sharing Incentive Plan
PLRs	Private Letter Rulings
PRPs	Potentially Responsible Parties
Preferred Securities	FPC-obligated mandatorily redeemable preferred securities of FPC Capital I
Preferred Stock	Progress Energy Florida Preferred Stock, $100 par value
Progress Capital	Progress Capital Holdings, Inc.
Progress Energy or the Parent	Progress Energy, Inc.
Progress Fuels	Progress Fuels Corporation, formerly Electric Fuels Corporation
Progress Rail	Progress Rail Services Corporation
PSSP	Performance Share Sub-Plan
PTC	Progress Telecommunications Corporation
PT LLC	Progress Telecom LLC
PVI	Progress Ventures, Inc., formerly referred to as Energy Ventures, a business unit of Progress Energy
PUHCA	Public Utility Holding Company Act of 1935, as amended
PURPA	Public Utility Regulatory Policies Act of 1978
PWR	Pressurized Water Reactors
QFs	Qualifying facilities
RAFT	Railcar Asset Financing Trust
RBCA or Global RBCA	Risk-based corrective action
Rail	Rail Services
RCA	Revolving credit agreement
ROE	Return on equity
RSA	Restricted stock agreement
RTO	Regional Transmission Organization
SEC	United States Securities and Exchange Commission
Section 29	Section 29 of the Internal Revenue Service Code
Service Company	Progress Energy Service Company, LLC
SFAS No. 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 123	Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative and Hedging Activities"
SFAS No. 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations"
SFAS No. 144	Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS No. 148	Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – An Amendment of FASB Statement No. 123"
SMD NOPR	Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission and Standard Market Design
SNF	Spent Nuclear Fuel
SO_2	Sulfur dioxide
Tax Agreement	Intercompany Income Tax Allocation Agreement
the Trust	FPC Capital I
Winchester Energy	Winchester Energy Company, LTD. (formerly Westchester Gas Company)
Winchester Production	Winchester Production Company, Ltd., an indirectly wholly owned subsidiary of Progress Fuels

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

Certain matters discussed throughout this Form 10-K 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 Form 10-K, include 1) PART II, ITEM 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" including, but not limited to, statements under the "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2007 and future financing plans and 2) statements made in the "Risk Factors" sections.

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 neither Florida Progress nor Progress Energy Florida (PEF) undertakes any 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 government laws and regulations, including those relating to the environment; deregulation or restructuring in the electric industry that may result in increased competition and unrecovered (stranded) costs; the ability of the Parent to implement its cost management initiatives as planned; the uncertainty regarding the timing, creation and structure of GridFlorida or other regional transmission organizations; weather conditions that directly influence the demand for electricity; the Company's ability to recover through the regulatory process, and the timing of such recovery of, the costs associated with the four hurricanes that impacted our service territory in 2004 or other 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 the Company and its subsidiaries' commercial and industrial customers; the ability of the Company's subsidiaries to pay upstream dividends or distributions to it; the impact on the facilities and the businesses of the Company from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks; the ability to successfully access capital markets on favorable terms; the impact of the Company's financial condition and ability to meet its cash and other financial obligations in the event its credit ratings are downgraded below investment grade; the impact that increases in leverage and the affect it may have on the Company; the ability of the Company to maintain its current credit ratings; the impact of derivative contracts used in the normal course of business by the Company; investment performance of pension and benefit plans; the Company's ability to control costs, including pension and benefit expense, and achieve its cost management targets for 2007; the availability and use of Internal Revenue Code Section 29 (Section 29) tax credits by synthetic fuel producers and the Company's continued ability to use Section 29 tax credits related to its coal and synthetic fuel businesses; the impact to the Company's financial condition and performance in the event it is determined the Company is not entitled to previously taken Section 29 tax credits; the impact of future accounting pronouncements regarding uncertain tax positions; the outcome of PEF's rate proceeding in 2005 regarding its future base rates; the Company's ability to manage the risks involved with the operation of its nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history; the Company's ability to manage the risks associated with its energy marketing operations; 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 the Company's subsidiaries.

These and other risk factors are detailed from time to time in the Company's and PEF's filings with the United States Securities and Exchange Commission (SEC). Many, but not all, of the factors that may impact actual results are discussed in the "Risk Factors" sections of this report. You should carefully read the "Risk Factors" sections of this report. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond the control of the Company and PEF. 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 the Company and PEF.

PART I

ITEM 1. BUSINESS

GENERAL

COMPANY

Florida Progress Corporation (Florida Progress or the Company, which term includes consolidated subsidiaries unless otherwise indicated) is a wholly owned subsidiary of Progress Energy, Inc. (Progress Energy), a registered holding company under the Public Utility Holding Company Act (PUHCA) of 1935. Progress Energy and its subsidiaries, including Florida Progress, are subject to the regulatory provisions of PUHCA. Florida Progress was incorporated in Florida on January 21, 1982. Florida Progress is the parent company of Florida Power Corporation (Florida Power or the Utility) and certain other subsidiaries. Progress Energy controls Florida Power Corporation and the other Florida Progress subsidiaries through its ownership of Florida Progress.

On November 30, 2000, the acquisition of Florida Progress by CP&L Energy, Inc. (CP&L Energy) became effective. In December 2000, CP&L Energy was renamed Progress Energy, Inc.

Effective January 1, 2003, Florida Power began doing business under the name Progress Energy Florida, Inc. (PEF). The legal name of the entity has not been changed and there is no restructuring of any kind related to the name change. The current corporate and business unit structure remains unchanged.

Florida Progress' revenues for the year ended December 31, 2004, were $5.9 billion, and assets at year-end were $9.7 billion. PEF's revenues for the year ended December 31, 2004, were $3.5 billion, and assets at year-end were $7.9 billion. Florida Progress' principal executive offices are located at 410 South Wilmington Street, Raleigh, North Carolina 27601-1748, telephone number (919) 546-6111. Information about Florida Progress and its subsidiaries can be found at Progress Energy's home page on the Internet at http://www.progress-energy.com, the contents of which are not and shall not be deemed to be a part of this document or any other Securities and Exchange Commission (SEC) filing. The Company makes available free of charge on its Web site its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to these reports as soon as reasonably practicable after such material is electronically filed or furnished to the SEC.

Florida Progress' principal business segment is PEF, which encompasses all regulated public utility operations. Florida Progress' other business segments, including Energy and Related Services, Rail Services, and Other, represent its diversified operations (See ITEM 1 "Business – Diversified Operations").

Progress Capital Holdings, Inc. (Progress Capital) is the downstream holding company for Florida Progress' diversified subsidiaries and provides a portion of the financing for the nonutility operations. Diversified operations include Progress Fuels Corporation (Progress Fuels), formerly Electric Fuels Corporation (Electric Fuels), and Progress Telecommunications Corporation (PTC). In January 2002, Electric Fuels changed its name to Progress Fuels. Progress Fuels is a diversified nonutility energy company, whose principal business segments are Energy and Related Services and Rail Services. The Company's Other category consists primarily of PTC, the Company's Investment in FPC Capital I, and the holding company, Florida Progress. PTC is a provider of wholesale telecommunications services.

After the acquisition of Florida Progress, Progress Energy hired a financial adviser to assist Florida Progress in evaluating its strategic alternatives with respect to Progress Fuels' Inland Marine Transportation and Rail Services segments. In November 2001, the Inland Marine Transportation segment was sold to AEP Resources, Inc.

During 2001, Progress Energy decided to retain the Rail Services segment in the near term. In December 2002, the Progress Energy Board of Directors adopted a resolution approving the sale of Railcar Ltd., a subsidiary included in the Rail Services segment. In March 2003, Progress Energy signed a letter of intent to sell the majority of Railcar Ltd., assets to The Andersons, Inc. The asset purchase agreement was signed in November 2003, and the transaction closed in February 2004.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt (See Note 23).

SIGNIFICANT DEVELOPMENTS

Sale of Natural Gas Assets

In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd., (Winchester Production), an indirectly wholly owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Energy and Related Services Segment. Net proceeds of approximately $251 million were used to reduce debt (See Note 4A).

2004 Hurricanes

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of PEF's service territory during the third quarter of 2004. As of December 31, 2004, restoration of PEF's systems from hurricane related damage was estimated at $385 million (See Note 3).

Divestiture of Synthetic Fuel Partnership Interests

In June 2004, the Company, through its subsidiary Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 (See Note 4B).

Progress Telecommunications Corporation Business Combination

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. 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 holds a 55% ownership interest in and is the parent of PT LLC (See Note 5A).

Mesa Hydrocarbons, Inc. Divestiture

In October 2003, the Company sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels. Net proceeds of approximately $97 million were used to reduce debt (See Note 4D).

Acquisition of Natural Gas Reserves

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (Bcf) from Republic Energy, Inc. and three other privately owned companies, all headquartered in Texas. The total cash purchase price for the transactions was approximately $168 million (See Note 5B).

Railcar Ltd. Divestiture

In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc. The asset purchase agreement was signed in November 2003, and the transaction closed on February 12, 2004. Net proceeds of approximately $75 million were used to reduce debt (See Note 4C).

Westchester Acquisition

In April 2002, Progress Fuels acquired 100% of Westchester Gas Company. During 2004, the name of the company was changed to Winchester Energy Company, Ltd. (Winchester Energy). The acquisition included approximately 215 natural gas-producing wells, 52 miles of intrastate gas pipeline and 170 miles of gas-gathering systems. The aggregate purchase price was approximately $153 million (See Note 5C).

UTILITY OPERATIONS - PEF

GENERAL

PEF, incorporated in Florida in 1899, is an operating public utility engaged in the generation, transmission, distribution and sale of electricity. At December 31, 2004, PEF had a total summer generating capacity (including jointly owned capacity) of approximately 8,544 MW.

PEF provided electric service during 2004 to an average of 1.5 million customers in west central Florida. Its service territory covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 21 municipal and nine rural electric cooperative systems. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Florida Power & Light Company, Tampa Electric Company and the City of Bartow. PEF is subject to the rules and regulations of the FERC, FPSC and the NRC. No single customer accounts for more than 10% of PEF's revenues.

BILLED ELECTRIC REVENUES

PEF's electric revenues billed by customer class for the last three years, are shown as a percentage of total PEF electric revenues in the table below:

BILLED ELECTRIC REVENUES

Revenue Class	**2004**	2003	2002
Residential	**53%**	55%	55%
Commercial	**25%**	24%	24%
Industrial	**8%**	7%	7%
Other retail	**6%**	6%	6%
Wholesale	**8%**	8%	8%

Important industries in PEF's territory include phosphate rock mining and processing, electronics design and manufacturing, and citrus and other food processing. Other important commercial activities are tourism, health care, construction and agriculture.

FUEL AND PURCHASED POWER

General

PEF's consumption of various types of fuel depends on several factors, the most important of which are the demand for electricity by PEF's customers, the availability of various generating units, the availability and cost of fuel and the requirements of federal and state regulatory agencies. PEF's total system generation (including jointly owned capacity) by primary energy source along with purchased power for the three years is presented in the following table:

ENERGY MIX PERCENTAGES

Fuel Type	**2004**	2003	2002
Coal [(a)]	**32%**	36%	33%
Oil	**16%**	16%	16%
Nuclear	**16%**	14%	15%
Gas	**16%**	13%	15%
Purchased Power	**20%**	21%	21%

(a) Amounts include synthetic fuel from unrelated third parties.

PEF is generally permitted to pass the cost of fuel and purchased power to its customers through fuel adjustment clauses. The future prices for and availability of various fuels discussed in this report cannot be predicted with complete certainty. See "Commodity Price Risk" under Item 7A, QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. However, PEF believes that its fuel supply contracts, as described below, will be adequate to meet its fuel supply needs.

PEF's average fuel costs per million Btu for the last three years were as follows:

AVERAGE FUEL COST
(per million Btu)

	2004	2003	2002
Coal (a)	**$ 2.30**	$ 2.42	$ 2.43
Oil	**4.67**	4.38	3.77
Nuclear	**0.49**	0.50	0.46
Gas	**6.41**	5.98	4.06
Weighted-average	**3.21**	3.07	2.60

(a) Amounts include synthetic fuel from unrelated third parties.

Changes in the unit price for coal, oil and gas are due to market conditions. Since these costs are primarily recovered through recovery clauses established by regulators, fluctuations do not materially affect net income.

Coal

PEF anticipates a combined requirement of approximately 6 million tons of coal in 2005. Approximately 70% of the coal is expected to be supplied from Appalachian coal sources in the United States and 30% supplied from coal sources in South America. Approximately 67% of the fuel is expected to be delivered by rail and the remainder by barge. All of this fuel is supplied by Progress Fuels, a subsidiary of Progress Energy, pursuant to contracts between PEF and Progress Fuels.

For 2005, Progress Fuels has medium-term and long-term contracts with various sources for approximately 115% of the burn requirements of PEF's coal units. Supply disruption caused by recent hurricanes has made it necessary to build inventories back to the traditional level of 45 days. These contracts have price adjustment provisions and have expiration dates ranging from 2005 to 2006. Progress Fuels will continue to sign contracts of various lengths, terms and quality to meet PEF's expected burn requirements. All the coal to be purchased for PEF is considered to be low sulfur coal by industry standards.

Oil and Gas

Natural gas and oil supply for PEF's generation fleet is purchased under term and spot contracts from several suppliers. The majority of the cost of PEF's oil and gas is determined by market prices as reported in certain industry publications. PEF believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEF's natural gas transportation is purchased under term firm transportation contracts with interstate pipelines. PEF also purchases capacity on a seasonal basis from numerous shippers and interstate pipelines to serve its peaking load requirements. PEF uses interruptible transportation contracts on certain occasions when available. PEF believes that existing contracts for oil are sufficient to cover its requirements if natural gas is unavailable during certain time periods.

Nuclear

Nuclear fuel is processed through four distinct stages. Stages I and II involve the mining and milling of the natural uranium ore to produce a uranium oxide concentrate and the conversion of this concentrate into uranium hexafluoride. Stages III and IV entail the enrichment of the uranium hexafluoride and the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

PEF has sufficient uranium, conversion, enrichment and fabrication contracts to meet its near-term nuclear fuel requirements needs. PEF's nuclear fuel contracts typically have terms ranging from five to ten years. For a discussion of PEF's plans with respect to spent fuel storage, see PART I, ITEM I, "Nuclear Matters."

Purchased Power

PEF, along with other Florida utilities, buys and sells power in the wholesale market on a short-term and long-term basis. At December 31, 2004, PEF had a variety of purchase power agreements for the purchase of approximately 1,498 MW of firm power. These agreements include (1) long-term contracts for the purchase of about 484 MW of purchased power with other investor-owned utilities, including a contract with The Southern Company for approximately 414 MW, and (2) approximately 821 MW of capacity under contract with certain QFs. The capacity currently available from QFs represents about 9% of PEF's total installed system capacity.

COMPETITION

Electric Industry Restructuring

PEF continues to monitor developments toward a more competitive environment and has actively participated in regulatory reform deliberations in Florida. Movement toward deregulation in this state has been affected by developments related to deregulation of the electric industry in other states.

In response to a legislative directive, the FPSC and the Florida Department of Environment and Protection submitted in February 2003 a joint report on renewable electric generating technologies for Florida. The report assessed the feasibility and potential magnitude of renewable electric capacity for Florida, and summarized the mechanisms other states have adopted to encourage renewable energy. The report did not contain any policy recommendations. The Company cannot anticipate when, or if, restructuring legislation will be enacted or if the Company would be able to support it in its final form.

Regional Transmission Organizations

As a result of Order 2000, PEF, Florida Power & Light Company and Tampa Electric Company (the Applicants) collectively filed with the FERC in October 2000 an application for approval of a GridFlorida RTO. The GridFlorida proposal is pending before both the FERC and the FPSC. The FERC provisionally approved the structure and governance of GridFlorida. 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 currently scheduled to be presented at a FPSC workshop on May 25, 2005, with subsequent action by the FPSC to be thereafter determined. It is unknown when the FERC or the FPSC will take final action with regard to the status of GridFlorida or what the impact of further proceedings will have on the Company's earnings, revenues or pricing. See Note 8C for a discussion of current developments of GridFlorida RTO.

Franchises

PEF holds franchises with varying expiration dates in 108 of the municipalities in which it distributes electric energy. PEF also serves 13 other municipalities and in all its unincorporated areas without franchise agreements. The general effect of these franchises is to provide for the manner in which PEF occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system.

Approximately 39% of PEF's total utility revenues for 2004 were from the incorporated areas of the 108 municipalities that had franchise ordinances during the year. Since 2000, PEF has renewed 34 expiring franchises and reached agreement on a franchise with a city that did not previously have a franchise. Franchises with five municipalities have expired without renewal.

All but 27 of the existing franchises cover a 30-year period from the date enacted. The exceptions are 23 franchises, each with a term of 10 years and expiring between 2005 and 2013; two franchises each with a term of 15 years and expiring in 2017; one 30-year franchise that was extended in 1999 for 5 years expiring in 2005; and one franchise with a term of 20 years expiring in 2020. Of the 108 franchises, 46 expire between January 1, 2005, and December 31, 2015, and 62 expire between January 1, 2016, and December 31, 2034.

Ongoing negotiations and, in some cases, litigation are taking place with certain municipalities to reach agreement on franchise terms and to enact new franchise ordinances (See Note 21E).

Stranded Costs

The largest stranded cost exposure for PEF is its commitment to QFs. PEF has taken a proactive approach to this industry issue. PEF continues to seek ways to address the impact of escalating payments from contracts it was obligated to sign under provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA).

REGULATORY MATTERS

General

PEF is subject to the jurisdiction of the FPSC with respect to, among other things, rates and service for electric energy sold at retail, retail service territory and issuances of securities. In addition, PEF is subject to regulation by the FERC with respect to transmission and sales of wholesale power, accounting and certain other matters. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus a reasonable rate of return on its equity. Increased competition as a result of industry restructuring may affect the ratemaking process.

Retail Rate Matters

The FPSC authorizes retail "base rates" that are designed to provide a utility with the opportunity to earn a specific rate of return on its "rate base," or average investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of utility operations and to provide investors with a fair rate of return.

In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC and is generally effective from May 1, 2002, through December 31, 2005. The Agreement eliminates the authorized Return on Equity (ROE) range normally used by the FPSC for the purpose of addressing earning levels, provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates. The Agreement is described in more detail in Note 8B.

In January 2005, in anticipation of the expiration of the Agreement, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2006. In its notice, PEF requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. The request for increased base rates is based on the fact that PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines 3 generation facility, extraordinary hurricane damage costs including capital costs which are not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of strong customer growth (See "Risk Factors").

Fuel and Other Cost Recovery

PEF's operating costs not covered by the utility's base rates include fuel, purchased power, energy conservation expenses and specific environmental costs. The state commission allows electric utilities to recover certain of these costs through various cost recovery clauses, to the extent the commission determines in an annual hearing that such costs are prudent. In addition, in December 2002, the FPSC approved an Environmental Cost Recovery Clause, which permits the Company to recover the costs of specified environmental projects to the extent these expenses are found to be prudent in an annual hearing and not otherwise included in base rates. Costs are recovered through this recovery clause in the same manner as the other existing clause mechanisms.

The FPSC determination results in the addition of a rider to a utility's base rates to reflect the approval of these costs and to reflect any past over- or under-recovery. Due to the regulatory treatment of these costs and the method allowed for recovery, changes from year to year have no material impact on operating results.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions. As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been

classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005 (See Note 3).

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period.

NUCLEAR MATTERS

PEF owns and operates one nuclear generating plant, Crystal River Unit No. 3 (CR3), which is subject to regulation by the Nuclear Regulatory Commission (NRC) under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974. 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. Nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications.

The nuclear power industry faces uncertainties with respect to the cost and long-term availability of sites for disposal of spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, nuclear plant operations, increased capital outlays for modifications, the technological and financial aspects of decommissioning plants at the end of their licensed lives and requirements relating to nuclear insurance.

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 2009. PEF currently has a 91.8% ownership interest in CR3. A condition of the operating license for the unit requires an approved plan for decontamination and decommissioning.

In 2002, the NRC sent a bulletin to companies that hold licenses for pressurized water reactors (PWRs) requiring information on the structural integrity of the reactor vessel head and a basis for concluding that the vessel head will continue to perform its function as a coolant pressure boundary. Inspection of the vessel head at CR3 was performed during a previous outage and no degradation of the reactor vessel head was identified.

In 2002, the NRC issued an additional bulletin dealing with head leakage due to cracks near the control rod nozzles, asking licensees to commit to high inspection standards to ensure the more susceptible plants have no cracks. PEF replaced the vessel head at CR3 during its regularly scheduled refueling outage in 2003.

In 2003, the NRC issued an order requiring specific inspections of the reactor pressure vessel head and associated penetration nozzles at PWRs. The Company responded, stating that it intended to comply with the provisions of the Order. The NRC also issued a bulletin requesting PWR licensees to address inspection plans for reactor pressure vessel lower head penetrations. The Company completed a bare metal visual inspection of the vessel bottom at CR3 during its 2003 outage and found no signs of corrosion or leakage at the unit. The Company plans to do additional, more detailed inspections as part of the next scheduled 10-year in-service inspection.

In February 2004, the NRC issued a revised Order for inspection requirements for reactor pressure vessel heads at PWRs. The Company has reviewed the required inspection frequencies and has incorporated them into long-range plans. CR3 will be required to inspect its new head within 7 years or four refueling outages after replacement. CR3 plans to inspect its new head prior to the end of 2009.

ENVIRONMENTAL MATTERS

There are two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation costs. In addition, there are distribution substations and transformers which are also anticipated to incur investigation and remediation costs. Presently, PEF cannot determine the total costs that may be included in connection with the remediation of all sites. See Note 20 for further discussion of these environmental matters.

DIVERSIFIED OPERATIONS

General

Florida Progress' diversified operations are owned directly or indirectly through Progress Capital, a Florida corporation and wholly owned subsidiary of Florida Progress. Progress Capital holds the capital stock of, and provides the financing for, Florida Progress' nonutility subsidiaries. Its primary subsidiary is Progress Fuels, formerly Electric Fuels. In January 2002, Electric Fuels changed its name to Progress Fuels.

Formed in 1976, Progress Fuels is an energy and transportation company. When the Inland Marine Transportation unit was sold in November 2001, Progress Fuels was reorganized into two business units: Energy and Related Services and Rail Services.

Energy and Related Services

Progress Fuels' Energy and Related Services business unit supplies coal to Florida Power's Crystal River Energy Complex and other utility and industrial customers. This business unit has subsidiaries that produce natural gas and oil products, blend and transload coal, mine coal and produce a solid coal-based synthetic fuel.

Synthetic Fuel Tax Credits

The Company has 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 numerous risks.

Although the Company believes that it operates its synthetic fuel facilities in compliance with applicable legal requirements for taking the credits, its four Earthco facilities are under audit by the IRS. IRS field auditors have taken an adverse position with respect to the Company's compliance with one of these legal requirements, and if the Company fails to prevail with respect to this position it could incur significant liability and/or lose the ability to claim the benefit of tax credits carried forward or generated in the future. Similarly, the Financial Accounting Standards Board may issue new accounting rules that would require that uncertain tax benefits (such as those associated with the Earthco plants) be probable of being sustained in order to be recorded on the financial statements; if adopted, this provision could have an adverse financial impact on the Company.

The Company's ability to utilize tax credits is dependent on having sufficient tax liability. Any conditions that negatively impact the Company's tax liability, such as weather, could also diminish the Company's ability to utilize credits, including those previously generated, and the synthetic fuel is generally not economical to produce absent the credits. Finally, the tax credits associated with synthetic fuels may be phased out if market prices for crude oil exceed certain prices.

The Company's synthetic fuel operations and related risks are described in more detail in Note 21 and in the "Risk Factors" section.

Rail Services

The Rail Services business segment, led by Progress Rail Services Corporation (Progress Rail), is one of the largest integrated and diversified suppliers of railroad and transit system products and services in North America and is headquartered in Albertville, Alabama. Rail Services' principal business functions include two business units: the Locomotive and Railcar Services (LRS) and Engineering and Track-work Services (ETS).

The LRS unit is primarily focused on railroad rolling stock that includes freight cars, transit cars and locomotives, the repair and maintenance of these units, the manufacturing or reconditioning of major components for these units and scrap metal recycling. The ETS unit focuses on rail and other track components, the infrastructure which supports the operation of rolling stock, as well as the equipment used in maintaining the railroad infrastructure and right-of-way. The Recycling division of the LRS unit supports both business units through its reclamation of reconditionable material and is a major supplier of recyclable scrap metal to North American steel mills and foundries through its processing locations as well as its scrap brokerage operations.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 23 for more information.

In March 2003, the Company signed a letter of intent to sell Railcar Ltd., to The Andersons, Inc. The asset purchase agreement was signed in November 2003, and the transaction closed in February 2004.

With operations in 23 states, Canada and Mexico, Progress Rail offers a full range of railcar parts, maintenance-of-way equipment, rail and other track material, railcar repair facilities, railcar scrapping and metal recycling as well as railcar sales and leasing.

PROGRESS TELECOM LLC

In December 2003, PTC and Caronet, both indirectly 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 PT LLC, a subsidiary of PTC. Subsequently, the stock of Caronet, a Progress Energy Carolinas subsidiary, was sold to an affiliate of Odyssey for $2 million in cash and Caronet became an indirect wholly owned subsidiary of Odyssey. Following consummation of all the transactions described above, PTC holds a 55% ownership interest in, and is the parent of, PT LLC. The accounts of PT LLC have been included in the Company's Financial Statements since the transaction date.

PT LLC has data fiber network transport capabilities that stretch from New York to Miami, Florida, with gateways to Latin America and conducts primarily a carrier's carrier business. PT LLC markets wholesale fiber-optic-based capacity service in the Eastern United States to long-distance carriers, Internet service providers and other telecommunications companies. PT LLC also markets wireless structure attachments to wireless communication companies and governmental entities. At December 31, 2004, PT LLC owned and managed approximately 8,500 route miles and more than 420,000 fiber miles of fiber-optic cable.

PT LLC competes with other providers of fiber-optic telecommunications services, including local exchange carriers and competitive access providers, in the Eastern United States.

Lease revenue for dedicated transport and data services is generally billed in advance on a fixed rate basis and recognized over the period the services are provided. Revenues relating to design and construction of wireless infrastructure are recognized upon completion of services (i.e., as the revenue is earned) for each completed phase of design and construction.

For additional information regarding asset and investment impairments related to the Company's investments in the telecommunications industry, see Note 10 to the Financial Statements.

COMPETITION

Florida Progress' nonutility subsidiaries compete in their respective marketplaces in terms of price, quality of service, location and other factors. Progress Fuels competes in several distinct markets. Its coal and synthetic fuel operations compete in the eastern United States industrial coal markets, and its rail operations compete in the railcar repair, parts and associated services markets primarily in the eastern United States, but also in the midwest, west, Canada and Mexico. Factors contributing to Progress Fuels' success in these markets include a competitive cost structure and strategic locations. There are, however, numerous competitors in each of these markets, although no one competitor is dominant in any industry.

Progress Fuels' gas production operations compete in the East Texas/North Louisiana region. Factors contributing to success include a competitive cost structure. Although there are numerous small, independent competitors in this market, the major oil and gas producers dominate this industry.

ITEM 2. PROPERTIES

GENERAL

Florida Progress believes that its physical properties and those of its subsidiaries are adequate to carry their businesses as currently conducted. Florida Progress and its subsidiaries maintain property insurance against loss or damage by fire or other perils to the extent that such property is usually insured.

UTILITY OPERATIONS

At December 31, 2004, PEF's 14 generating plants represent a flexible mix of fossil, nuclear, combustion turbine and combined cycle resources with a total summer generating capacity (including jointly owned capacity) of 8,544 MW. At December 31, 2004, PEF had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEF Ownership (in %)	Summer Net Capability (a) (in MW)	
STEAM TURBINES							
Anclote	Holiday, Fla.	2	1974-1978	Gas/Oil	100	993	
Bartow	St. Petersburg, Fla.	3	1958-1963	Gas/Oil	100	444	
Crystal River	Crystal River, Fla.	4	1966-1984	Coal	100	2,302	
Suwannee River	Live Oak, Fla.	3	1953-1956	Gas/Oil	100	143	
	Total	12				3,882	
COMBINED CYCLE							
Hines	Bartow, Fla.	2	1999-2003	Gas/Oil	100	998	
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	207	
	Total	3				1,205	
COMBUSTION TURBINES							
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	52	
Bartow	St. Petersburg, Fla.	4	1958-1972	Gas/Oil	100	187	
Bayboro	St. Petersburg, Fla.	4	1973	Oil	100	184	
DeBary	DeBary, Fla.	10	1975-1992	Gas/Oil	100	667	
Higgins	Oldsmar, Fla.	4	1969-1970	Gas/Oil	100	122	
Intercession City	Intercession City, Fla.	14	1974-2000	Gas/Oil	100 (c)	1,041	(b)
Rio Pinar	Rio Pinar, Fla.	1	1970	Oil	100	13	
Suwannee River	Live Oak, Fla.	3	1980	Gas/Oil	100	164	
Turner	Enterprise, Fla.	4	1970-1974	Oil	100	154	
University of Florida Cogeneration	Gainesville, Fla.	1	1994	Gas	100	35	
	Total	47				2,619	
NUCLEAR							
Crystal River	Crystal River, Fla.	1	1977	Uranium	91.78	838	(b)
	Total	1				838	
TOTAL		63				8,544	

(a) Amounts represent PEF's net summer peak rating, gross of co-ownership interest in plant capacity.

(b) Facilities are jointly owned. The capacities shown include joint owners' share.

(c) PEF and Georgia Power Company (Georgia Power) are co-owners of a 143 MW advanced combustion turbine located at PEF's Intercession City site (P11). Georgia Power has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year.

At December 31, 2004, PEF had total capacity resources of approximately 10,042 MW, including both the total generating capacity of 8,544 MW and the total firm contracts for purchased power of 1,498 MW.

Several entities have acquired undivided ownership interests in CR3 in the aggregate amount of 8.22%. The joint ownership participants are: City of Alachua – 0.08%, City of Bushnell – 0.04%, City of Gainesville – 1.41%, Kissimmee Utility Authority – 0.68%, City of Leesburg – 0.82%, Utilities Commission of the City of New Smyrna Beach – 0.56%, City of Ocala – 1.33%, Orlando Utilities Commission - 1.60% and Seminole Electric Cooperative, Inc. – 1.70%. PEF and Georgia Power are co-owners of a 143 MW advance combustion turbine located at PEF's Intercession City site (P11). Georgia Power has the exclusive right to the output of this unit during the months of June through September. PEF has that right for the remainder of the year. Otherwise, PEF has good and marketable title to its principal plants and important units, subject to the lien of its mortgage and deed of trust, with minor exceptions, restrictions and reservations in conveyances, as well as minor defects of the nature ordinarily found in properties of similar character and magnitude. PEF also owns certain easements over private property on which transmission and distribution lines are located.

At December 31, 2004, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and 1,500 miles of 230 kV lines. PEF also had 22,000 circuit miles of overhead distribution conductor and 13,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 45,000,000 kVA in 616 transformers. Distribution line transformers numbered approximately 365,000 with an aggregate capacity of about 18,000,000 kVA.

DIVERSIFIED OPERATIONS

Progress Fuels controls, either directly or through subsidiaries, coal reserves located in eastern Kentucky and southeastern Virginia of approximately 46 million tons and controls, through mineral leases, additional estimated coal reserves of approximately 48 million tons. The reserves controlled include substantial quantities of high quality, low sulfur coal that is appropriate for use at PEF's existing generating units. Progress Fuels' total production of coal during 2004 was approximately 3.4 million tons.

In connection with its coal operations, Progress Fuels' business units own and operate surface and underground mines, coal processing and loadout facilities in southeastern Kentucky and southwestern Virginia. Other subsidiaries own and operate a river terminal facility in eastern Kentucky, a railcar-to-barge loading facility in West Virginia, two bulk commodity terminals on the Kanawha River near Charleston, West Virginia and a bulk commodity terminal on the Ohio River near Huntington, West Virginia. Progress Fuels and its subsidiaries employ both Company and contract miners in their mining activities.

Progress Fuels has oil and gas leases in East Texas and Louisiana with total proven oil and gas reserves of approximately 247 billion cubic feet equivalent. Progress Fuels' oil and gas production in 2004 was 30.4 billion cubic feet equivalent. The following provides further information on the oil and gas operations (See Note 22).

Gross and net developed and undeveloped acreage at December 31, 2004 follow:

	Developed		**Undeveloped**	
	Gross	**Net**	**Gross**	**Net**
United States	**94,891**	**67,300**	**15,797**	**13,291**

The number of gross and net development wells completed during each of the years ending December 31 follows:

	2004		2003		2002	
(in millions)	**Gross**	**Net**	Gross	Net	Gross	Net
Development Wells:						
Productive	**90**	**74**	110	101	51	44
Dry	**1**	**1**	2	2	-	-
Total Development	**91**	**75**	112	103	51	44

The number of productive oil and gas wells at December 31, 2004, follows:

	Oil		Gas	
(in millions)	Gross	Net	Gross	Net
United States	**55**	**51**	**363**	**336**

OTHER

Progress Rail, a Progress Fuels subsidiary, is one of the largest integrated processors of railroad materials in the United States, and is a leading supplier of new and reconditioned freight car parts; rail, rail welding and track work components; railcar repair facilities; railcar and locomotive leasing; maintenance-of-way equipment and scrap metal recycling. It has facilities and offices in 23 states, Mexico and Canada.

Progress Rail owns and/or operates approximately 2,000 railcars and 50 locomotives that are used for the transportation and shipping of coal, steel, and other bulk products.

PTC provides wholesale telecommunications services throughout the Eastern United States. PT LLC incorporates more than 420,000 fiber miles in its network, including over 189 Points-of-Presence, or physical locations where a presence for network access exists.

ITEM 3. LEGAL PROCEEDINGS

1. **Calgon Carbon Corporation v. Potomac Capital Investment Corporation, Potomac Electric Power Company, Progress Capital Holdings, Inc., and Florida Progress Corporation, United States District Court for the Western District of Pennsylvania, Civil Action No. 98-0072.**

In 1996, Florida Progress sold its 80% interest in Advanced Separation Technologies (AST) to Calgon Carbon Corporation (Calgon) for net proceeds of $56 million in cash. In 1998, Calgon filed a lawsuit against Florida Progress and the other selling shareholder and amended it in April 1998, alleging misstatement of AST's 1996 revenues, assets and liabilities, seeking damages and granting Calgon the right to rescind the sale. The lawsuit also accused the sellers of failing to disclose flaws in AST's manufacturing process and a lack of quality control.

All parties filed motions for summary judgment in July 2001. The summary judgment motions of Calgon and the other selling shareholder were denied in April 2002. The summary judgment motion of Florida Progress was withdrawn pending a legal challenge to portions of the report of Calgon's expert, Arthur Andersen, which had been used to oppose summary judgment. In September 2003, the United States District Court for the Western District of Pennsylvania issued final orders excluding from evidence in the case that portion of Arthur Andersen's damage analysis based on the discounted cash flow methodology of valuation. The Court did not exclude Arthur Andersen's use of the guideline publicly traded company methodology in its damage analysis. Florida Progress filed a renewed motion for summary judgment in October 2003, which is pending. Because the motion has now been outstanding for over a year, a ruling on the motion is expected at any time.

Florida Progress believes that the aggregate total of all legitimate warranty claims by customers of AST for which it is probable that Florida Progress will be responsible under the Stock Purchase Agreement with Calgon is approximately $3 million, and accordingly, accrued $3 million in the third quarter of 1999 as an estimate of probable loss. The Company cannot predict the outcome of this matter, but will vigorously defend against the allegations (See Note 21).

2. **U.S. Global, LLC v. Progress Energy, Inc. et al., Case No. 03004028-03 Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC, Case No. 03004028-03**

A number of Progress Energy, Inc. 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 (1) an interest in two synthetic fuel facilities currently owned by the Progress Affiliates, and (2) 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, Florida, 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, North Carolina, seeking declaratory relief consistent with the Company's 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 Company cannot predict the outcome of these matters, but will vigorously defend against the allegations.

For a discussion of certain other legal matters, see Note 21 to the Financial Statements.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The information called for by ITEM 4 is omitted pursuant to Instruction I (2) (c) to Form 10-K (Omission of Information by Certain Wholly owned Subsidiaries).

PART II

ITEM 5. MARKET FOR THE REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

FLORIDA PROGRESS

Since November 2000, all of Florida Progress' common stock is owned by Progress Energy, and as a result there is no established public trading market for the stock. Since the Progress Energy acquisition Florida Progress has not issued or repurchased any equity securities. Florida Progress receives dividends from PEF. PEF has provisions restricting dividends in certain limited circumstances (See Note 12B). FPC did not issue or repurchase any equity securities during 2004. FPC does not have any equity compensation plans under which its equity securities are issued.

PEF

All of PEF's common stock is owned by Florida Progress, and as a result there is no established public trading market for the stock. For the past three years, PEF has paid quarterly dividends to Florida Progress totaling the amounts shown in the Statements of Common Equity in the Financial Statements. PEF has provisions restricting dividends in certain circumstances (See Note 12B). PEF did not issue or repurchase any equity securities during 2004. PEF does not have any equity compensation plans under which its equity securities are issued.

ITEM 6. SELECTED FINANCIAL DATA

The information called for by ITEM 6 is omitted pursuant to Instruction I (2) (a) to Form 10-K (Omission of Information by Certain Wholly owned Subsidiaries).

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

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

Overview

Florida Progress' income from continuing operations for the years ended December 31, 2004 and 2003 were $474 million and $443 million, respectively. The increase in income from continuing operations in 2004 is primarily due to:

- **Reduction in revenue sharing provisions in Florida.**
- **Favorable customer growth at the utility.**
- **Increased margins as a result of the allowed return on the Hines 2 Plant at the utility.**
- **Increased earnings for natural gas operations, which include the gain recorded on the disposition of certain gas** assets.
- Increased earnings for Rail operations.

Partially offsetting these items were the:

- **Reduction in synthetic fuel earnings** due to lower synthetic fuel sales due to the impact of hurricanes during the **year.**
- **Reduction in revenues due to customer** outages in Florida associated with the hurricanes.
- **Increased interest charges due to the** reversal of interest expense for resolved tax matters in 2003.

These and other key operating results are discussed by segment below.

Progress Energy Florida

PEF's operating results are primarily influenced by customer demand for electricity, its ability to control costs and its regulatory return on equity. Annual demand for electricity is based on the number of customers, their annual usage and the impact of weather. Since PEF serves a predominately retail customer base, operating results are primarily influenced by the level of retail sales and the costs associated with those sales. In addition, the current economic conditions in the service territories may impact the annual demand for electricity.

The FPSC oversees the retail sales of the state's investor-owned electric utilities and authorizes retail base rates. Base rates and the resulting base revenues are intended to cover certain reasonable and prudent expenses of utility operations and provide investors with a fair rate of return.

Costs not covered by base rates include fuel, purchased power, energy conservation expenses and certain environmental costs. The FPSC allows electric utilities to recover these costs, referred to as "pass-through" costs, through various cost recovery clauses to the extent those costs are prudent. Due to the regulatory treatment of these expenses and the method allows for recovery, changes from year to year have no material impact on operating results.

PEF contributed segment profits of $333 million and $295 million in 2004 and 2003, respectively. 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 2 plant 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. The decrease in profits in 2003, when compared to 2002, was primarily due to the impact of the 2002 rate case stipulation, higher benefit-related costs primarily related to higher pension expense, higher depreciation and the unfavorable impact of weather. These amounts were partially offset by continued customer growth and lower interest charges.

PEF's profits in 2004 and 2003 were affected by the outcome of the Florida Power rate case stipulation, which included a one-time retroactive revenue refund in 2002, a decrease in retail rates of 9.25% (effective May 1, 2002), provisions for revenue sharing with the retail customer base, lower depreciation and amortization and increased service revenue rates (See Note 8B).

A comparison of the results of operations of PEF for the past two years follows:

REVENUES

PEF's electric revenues for the years ended December 31, 2004, 2003 and 2002 and the percentage change by year and by customer class, as well as the impact of the rate case settlement on revenue, are as follows:

(in millions)					
Customer Class	**2004**	% Change	2003	% Change	2002
Residential	**$ 1,806**	6.8	$ 1,691	2.8	$ 1,645
Commercial	**853**	15.3	740	1.2	731
Industrial	**254**	16.0	219	3.8	211
Governmental	**211**	16.6	181	4.6	173
Revenue sharing refund	**(11)**	–	**(35)**	–	(5)
Retroactive retail rate refund	–	–	–	–	(35)
Total retail revenues	**$ 3,113**	11.3	$ 2,796	2.8	$ 2,720
Wholesale	**268**	18.1	227	(1.3)	230
Unbilled	**7**	–	(2)	–	(3)
Miscellaneous	**137**	4.6	131	13.9	115
Total electric revenues	**$ 3,525**	11.8	$ 3,152	2.9	$ 3,062

PEF's electric energy sales for the years ended December 31, 2004, 2003 and 2002 and the percentage change by year and by customer class are as follows:

(in thousands of MWh)					
Customer Class	**2004**	% Change	2003	% Change	2002
Residential	**19,347**	(0.4)	19,429	3.6	18,754
Commercial	**11,734**	1.6	11,553	1.2	11,420
Industrial	**4,069**	1.7	4,000	4.3	3,835
Governmental	**3,044**	2.4	2,974	4.4	2,850
Total retail energy sales	**38,194**	0.6	37,956	3.0	36,859
Wholesale	**5,101**	18.0	4,323	3.4	4,180
Unbilled	**358**	–	**233**	–	5
Total MWh sales	**43,653**	2.6	42,512	3.6	41,044

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 has 37,000 additional retail customers compared to prior year. Revenues were also favorably impacted by a reduction in the provision for revenue sharing of $24 million. Results for 2003 included an additional refund of $18 million related to the 2002 revenue sharing provision as ordered by the FPSC in July of 2003. In addition, improved wholesale sales increased revenues by $11 million. 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. These increases were partially offset by the reduction in revenues related to customer outages for Hurricanes Charley, Frances and Jeanne of approximately $12 million and the impact of milder weather in the current year of $10 million.

PEF's revenues, excluding recoverable fuel and other pass-through revenues of $1.692 billion and $1.602 billion in 2003 and 2002, respectively, were unchanged from 2002 to 2003. Revenues were favorably impacted by $49 million in 2003, primarily as a result of customer growth (approximately 36,000 additional customers). In addition, other operating revenues were favorable by $16 million due primarily to higher wheeling and transmission revenues and higher service charge revenues (resulting from increased rates allowed under the 2002 rate settlement). These increases were partially offset by the negative impact of the rate settlement, which decreased revenues, lower wholesale sales and the impact of unfavorable weather. The provision for revenue sharing increased $12 million in 2003 compared to the $5 million provision recorded in 2002. Revenues in 2003 were also impacted by the final resolution of the 2002 revenue sharing provisions as the FPSC issued an order in July of 2003 that required PEF to refund an additional $18 million to customers related to 2002. The 9.25% rate reduction from the settlement accounted for an additional $46 million decline in revenues. The 2003 impact of the rate settlement was partially

offset by the absence of the prior year interim rate refund of $35 million. Lower wholesale revenues (excluding fuel revenues) of $17 million and the $8 million impact of milder weather also reduced base revenues during 2003.

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 is subject to recovery is deferred for future collection or refund to customers.

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. In November 2003, the FPSC approved PEF's request for a cost adjustment in its annual fuel filing due to the rising costs of fuel. The new rates became effective January 2004.

Operations and Maintenance (O&M)

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.

O&M expenses were $640 million in 2003, which represents a $49 million increase when compared to the prior year. The increase is largely related to increases in certain benefit-related expenses of $36 million, which consisted primarily of higher pension expense of $27 million and higher operational costs related to the CR3 nuclear outage and plant maintenance.

Depreciation and Amortization

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 that was 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 2 in the revenues analysis above.

Depreciation and amortization was $307 million in 2003, which represents an increase of $12 million when compared to 2002. Depreciation increased primarily as a result of additional assets being placed into service that were partially offset by lower amortization of the Tiger Bay regulatory asset of $2 million, which was fully amortized in September 2003.

Taxes other than on income

Taxes other than on income were $254 million in 2004, which represents an increase of $13 million compared to the prior year. 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.

Taxes other than on income were $241 million in 2003, which represents an increase of $13 million compared to prior year. This increase was due to increases in payroll taxes of $10 million and increases in gross receipts and franchise taxes of $4 million combined.

Interest Expense

Interest charges, net were $114 million in 2004, which represents an increase of $23 million compared to the prior year. Interest charges, net were $91 million in 2003, which represents a $15 million decrease compared to 2002. The fluctuations were 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 $174 million, $147 million and $163 million in 2004, 2003 and 2002, respectively. In 2004, 2003 and 2002, $14 million, $13 million and $20 million, respectively, of the tax benefit that was previously held at Progress Energy holding company was allocated to PEF. As required by an SEC order issued in 2002, certain holding company tax benefits are allocated to profitable subsidiaries. Other fluctuations in income taxes are primarily due to changes in pretax income.

Progress Fuels Corporation

Progress Fuels makes up the majority of Florida Progress' diversified operations. The results of operations for Progress Fuels' Energy and Related Services and Rail Services units are discussed below.

Energy and Related Services – Income from continuing operations for Energy and Related Services were $137 million and $166 million for 2004 and 2003, respectively. The following summarizes Energy and Related Services' segment profits for the years ended 2004 and 2003:

(in millions)	2004	2003
Synthetic fuel operations	$ 57	$ 139
Natural gas operations	85	34
Coal fuel and other operations	(5)	(7)
Segment profits	$ 137	$ 166

SYNTHETIC FUEL OPERATIONS

Synthetic fuel operations generated profits of $57 million and $139 million for the years ended December 31, 2004 and 2003, respectively. The production and sale of the synthetic fuel generate operating losses, but qualify for tax credits under Section 29 of the Internal Revenue Code, which more than offset the effects of such losses. The operations resulted in the following losses (prior to tax credits) and tax credits for 2004 and 2003.

(in millions)	2004	2003
Tons sold	4.9	7.5
After-tax losses (excluding tax credits)	$(70)	$ (74)
Tax credits	127	213
Net Profit	$ 57	$ 139

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. The Company's total synthetic fuel production of approximately five million tons in 2004 is down compared to 2003 production levels of approximately eight million tons as a result of hurricane costs, which reduced the Company's projected 2004 regular tax liability and its corresponding ability to record tax credits from its synthetic fuel production.

As of September 30, 2004, the Company anticipated an ability to record approximately three million tons of production based on the Company's projected tax liability for 2004. This estimate was based upon the Company's projected casualty loss as a result of the storms. Therefore, the Company recorded a charge of $47 million in the third quarter for tax credits associated with approximately 1.8 million tons sold during the year that the Company anticipated it would not be able to use. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from customers over a two-year period. Based on a reasonable expectation at December 31, 2004, that the FPSC will grant the requested recovery of the storm costs, the Company's loss from the casualty is less than originally anticipated. Accordingly, as of December 31, 2004, the Company's anticipated 2004 tax liability supported credits on approximately five million tons. Therefore, the Company recorded tax credits of $55 million for the quarter ended December 31, 2004, for tax credits associated with approximately 2 million tons sold during the year that the Company now anticipates can be used. As of December 31, 2004, the Company

anticipates that approximately $5 million of tax credits associated with approximately 0.2 million tons sold during the year could not be used (See Note 21E). The Company ceased operations at its Earthco facilities for the last three months of 2004 due to the decrease in the Company's projected 2004 tax liability, and these facilities were restarted in January 2005.

The Company believes its right to recover storm costs is well established, however, the Company cannot predict the timing or outcome of this matter. If the FPSC should deny PEF's petition for the recovery of storm costs in 2005, there could be a material impact on the amount of 2005 synthetic fuels production and results of operations.

NATURAL GAS OPERATIONS

Natural gas operations generated profits of $85 million and $34 million for the years ended December 31, 2004 and 2003, respectively. Natural gas profits increased $51 million in 2004 compared to 2003 due primarily to the gain recognized on the sale of gas assets during the year. In December 2004, the Company 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 the Company's remaining oil and gas properties. 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. Volume and prices have increased 21% and 16%, respectively, for 2004 compared to 2003.

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

	2004	2003	2002
Production in Bcf equivalent			
East Texas/LA gas operations	**20**	13	6
North Texas gas operations	**10**	7	–
Mesa	**–**	5	7
Total production	**30**	25	13
Revenues in millions			
East Texas/LA gas operations	**$ 110**	$ 65	$ 24
North Texas gas operations	**52**	38	–
Mesa	**–**	13	15
Total revenues	**$ 162**	$ 116	$ 39
Gross margin			
In millions of $	**$ 126**	$ 91	$ 29
As a % of revenues	**78%**	78%	74%

RESULTS FROM PRODUCING ACTIVITIES

The following summarizes the results of operations of natural gas production operations:

Years ending December 31, ($ in millions except for averages)		**2004**		2003		2002
Gas production (Bcfe)		**30.4**		25.1		12.7
Average sales price:						
Gas (per Mcf)	**$**	**4.84**	$	4.24	$	2.77
Oil (per Bbl)	**$**	**41.06**	$	29.46	$	26.33
Average sales price combined (per Mcfe)	**$**	**4.95**	$	4.27	$	2.84
Average production cost (per Mcfe)	**$**	**0.92**	$	0.66	$	0.54
Revenue (millions)						
Gas	**$**	**168**	$	116	$	32
Oil	**$**	**11**	$	7	$	3
Hedging	**$**	**(28)**	$	(16)	$	1
Total revenue		**151**		107		36
Production costs	**$**	**28**	$	16	$	7

COAL FUEL AND OTHER OPERATIONS

Coal fuel and other operations generated losses of $5 million and $7 million for the years ended December 31, 2004 and, 2003, respectively. The increase in profits for 2004 is primarily due to higher volumes and margins for coal fuel operations of $16 million after-tax. A reduction in impairment losses of $2 million after-tax also increased coal earnings. An impairment of goodwill related to the Diamond May coal mine reduced earnings by $8 million before and after-tax (See Note 9). Results in 2003 included the recording of an impairment of certain assets at the Kentucky May coal mine of $10 million after-tax in 2003 (See Note 10). This favorability was offset by a reduction in profits of $7 million after-tax for fuel transportation operations related to the waterborne transportation ruling by the FPSC (See Note 8B). Profits were also negatively impacted by higher corporate costs of $10 million in 2004. Corporate cost in the prior year included $4 million of favorability related to the reduction of an environmental reserve (See Note 20). The remaining unfavorability in corporate costs is attributable to increased interest expense related to unresolved tax matters and higher professional fees.

The Company is exploring strategic alternatives regarding the Fuels' coal mining business, which could include divesting these assets. As of December 31, 2004 the carrying value of long-lived assets of the coal mining business were $62 million. The Company cannot currently predict the outcome of this matter.

RAIL SERVICES

Rail's operations represent the activities of Progress Rail Services Corporation (Progress Rail) and include railcar and locomotive repair, track-work, rail parts reconditioning and sales, scrap metal recycling, railcar leasing and other rail-related services.

Rail contributed segment profits of $16 million and losses of $1 million for the years ended December 31, 2004 and 2003, respectively. Results in 2004 were favorably impacted by the strong scrap metal market in 2004. Revenues were $1.131 billion in 2004, which represents an increase of $284 million compared to prior year. This increase is due primarily to increased volumes and higher prices in recycling operations and in part to increased production and sales in locomotive and railcar services and engineering and track services. Tonnage for recycling operations is up approximately 35% on an annualized basis compared to 2003. The increase in tonnage, coupled with an increase in the average index price of approximately 80%, accounts for the significant increase in revenues year over year. The American Metal Market index price for #1 rail road heavy melt (which is used as the index for buying and selling of railcars) has increased to $191 as of December 31, 2004, from $106 as of December 31, 2003. Cost of goods sold was $990 million in 2004, which represents an increase of $252 million compared to the prior year. The increase in costs of good sold is due to increased costs for inventory, labor and operations as a result of the increased volume in the recycling operations, locomotive and railcar services and engineering and track services. In addition, results in 2003 were negatively impacted by the retroactive reallocation of Service Company costs of $3 million after-tax. The favorability related to the reallocation was offset by an increase in general and administrative costs in 2004 related primarily to higher professional fees associated with divestiture efforts.

In February 2005, Progress Energy signed a definitive agreement to sell its Progress Rail subsidiary to subsidiaries of One Equity Partners LLC for a sales price of $405 million. Proceeds from the sale are expected to be used to reduce debt. See Note 22 for more information.

Other

The Other segment includes telecommunications, holding company and financing expenses and had net losses from continuing operations of $12 million and $17 million in 2004 and 2003, respectively.

PTC had net losses of $5 million and $3 million for 2004 and 2003, respectively. The increase in losses compared to prior year is due to an increase in fixed costs, mainly depreciation expense, and professional fees related to the merger with EPIK. In December 2003, PTC and Caronet, Inc., both indirectly wholly owned subsidiaries of Progress Energy, and EPIK Communications, Inc., a wholly owned subsidiary of Odyssey Telecorp, Inc., contributed substantially all of their assets and transferred certain liabilities to PT LLC, a subsidiary of PTC. Subsequently, the stock of Caronet, a subsidiary of Progress Energy Carolinas, was sold to an affiliate of Odyssey for $2 million in cash and Caronet became an indirect wholly owned subsidiary of Odyssey. Following consummation of all the transactions described above, PTC holds a 55 percent ownership interest in, and is the parent of PT LLC. Odyssey holds a combined 45 percent ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC are included in the Company's Financial Statements since the transaction date.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Florida Progress and PEF prepared their financial statements in accordance with accounting principles generally accepted in the United States. In doing so, certain estimates were made that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on its financial results and are subject to the greatest amount of subjectivity. Senior management has discussed the development and selection of these critical accounting policies with the Audit Committee of Progress Energy's Board of Directors.

Utility Regulation

PEF is subject to regulation that sets the prices (rates) it is permitted to charge customers based on the costs that regulatory agencies determine PEF is permitted to recover (See Note 8). 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 changing regulatory framework, a significant amount of regulatory assets have been recorded. PEF continually reviews 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 agency often provides flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets.

Asset Impairments

Florida Progress evaluates the carrying value of long-lived assets for impairment 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, 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. A high degree of judgment is required in developing estimates related to these evaluations and various factors are considered, including projected revenues and cost and market conditions.

In connection with a review of strategic alternatives regarding the Fuels' coal mining business, the Company performed an impairment test of the goodwill of the coal mining business in the fourth quarter of 2004. As a result of the impairment test, the Company recorded an impairment loss of $8 million to write off all of the goodwill of the coal mining business. The Company used a probability-weighted discounted cash flow analysis to perform the assessment.

Due to the reduction in coal production at the Kentucky May Coal Mine, the Company evaluated its long-lived assets in 2003 and recorded an impairment of $15 million on a pre-tax basis during the fourth quarter of 2003. See Note 10 to the Financial Statements for further information on this impairment. Fair value was determined based on discounted cash flows.

During 2002, Florida Progress recorded pre-tax long-lived asset impairments of $215 million related to its telecommunications business. See Note 10 to the Financial Statements for further information on this impairment and other charges. The fair value of these assets was determined using an external valuation study heavily weighted on a discounted cash flow methodology and using market approaches as supporting information.

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, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2004, 2003 or 2002.

Synthetic Fuels Tax Credits

As discussed in Note 21E, Florida Progress, through the Energy and Related Services business unit, owns facilities that produce synthetic fuel as defined under the Internal Revenue Code. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 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 amount of Section 29 credits that the Company is allowed to claim in any calendar year is limited by the amount of the Company's regular federal income tax liability. Synthetic fuel tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits on the Consolidated Balance Sheets. All of Florida Progress' synthetic fuel facilities have received PLRs from the IRS with respect to their operations, although these do not address placed-in-service date determinations. The PLRs do not limit the production on which synthetic fuel credits may be claimed. The current Section 29 tax credit program expires at the end of 2007. These tax credits are subject to review by the IRS, and if Progress Energy fails to prevail through the administrative or legal process, there could be a significant tax liability owed for previously taken Section 29 credits, with a significant impact on earnings and cash flows. Additionally, the ability to use tax credits currently being carried forward could be denied. See further discussion at Note 21E and in the "Risk Factors" section.

Pension Costs

As discussed in Note 15 to the Financial Statements, Florida Progress and PEF maintain qualified non-contributory defined benefit retirement (pension) plans. The reported costs of providing pension benefits 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 rates of return on plan assets and discount rates used in determining benefit obligations and annual costs. In addition, reported costs reflect certain delayed recognition features in the accounting model used to determine each year's cost.

Due to a decline in 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, Florida Progress lowered the discount rate to 5.9% at December 31, 2004, which will increase the 2005 benefit costs recognized, all other factors remaining constant. Plan assets performed well in 2004, with returns of approximately 14%. That positive asset performance will result in decreased pension cost in 2005, all other factors remaining constant. Evaluations of the effects of these and other factors have not been completed, but Florida Progress estimates that 2005 total cost recognized for pension will be approximately plus or minus $2 million of the amount recorded in 2004.

Florida Progress has pension plan assets with a fair value of approximately $919 million at December 31, 2004. Florida Progress' expected rate of return on pension plan assets is 9.25%. The Company reviews this rate on a regular basis. Under SFAS No. 87, "Employers' Accounting for Pensions" the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, Florida Progress would only adjust that return if its fundamental assessment of the debt and equity markets changes or its investment policy changes significantly. Florida Progress believes that its pension plans' asset investment mix and historical performance support the long-term rate of 9.25% being used. Florida Progress does not adjust the rate in response to short-term market fluctuations such as the abnormally high market return levels of the latter 1990's, recent years' market declines and the market rebound in 2003 and 2004. A 0.25% change in the expected rate of return for 2004 would have changed 2004 pension cost by approximately $2 million. Approximately 95% of Florida Progress' pension assets and obligations are attributable to PEF.

Another factor affecting Florida Progress' and PEF's pension cost, and sensitivity of the cost 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 9.25% long-term expected 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. Florida Progress uses the fair value method of determining market-related value. Changes in plan asset performance are reflected in pension cost sooner under the fair value method than the five-year averaging method and, therefore, pension cost tends to be more volatile using the fair value method.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Florida Progress' utility and diversified operations are capital-intensive businesses. Florida Progress relies upon its operating cash flow, commercial paper facilities and its ability to access long-term capital markets for its liquidity needs. Since a substantial majority of Florida Progress' operating costs are related to its regulated electric utility, a significant portion of these costs are recovered from customers through fuel and energy cost recovery clauses.

The Company and its subsidiaries participate in two internal money pools, operated by Progress Energy, to more effectively utilize cash resources and to reduce outside short-term borrowings. Short-term borrowing needs are met first by available funds of the money pool participants. Borrowing companies pay interest at a rate designed to approximate the cost of outside short-term borrowings. Subsidiaries, which invest in the money pool, earn interest on a basis proportionate to their average monthly investment. Funds may be withdrawn from or repaid to the pool at any time without prior notice.

At PEF, cash from operations is the primary source of cash for the utility's capital expenditures. PEF's estimated capital requirements for 2005, 2006 and 2007 are approximately $490 million, $450 million and $550 million, respectively. See Note 8D for a discussion of expected impacts on future capital expenditures due to changes in capitalization practice for PEF.

In addition to funding its construction and other commitments with cash from operations, the companies can access the capital markets through the issuance of commercial paper, committed lines of credit, secured and unsecured notes, preferred securities and equity from Progress Energy, which can offer issuances of common stock. Risk factors associated with commercial paper back up credit facilities and credit ratings are discussed below and in the "Risk Factors" section of this report.

PEF's interim financing needs are funded primarily through its commercial paper program and borrowings under its 364-day and 3-year revolving credit agreements (RCAs). PEF's commercial paper program is supported by its lines of credit and to the extent amounts are reserved for commercial paper, they are not available for additional borrowings. PEF plans to enter into a new five-year line of credit in 2005 that will replace these two facilities. In addition, PEF has an uncommitted bank bid facility that authorizes them to borrow and re-borrow. The facility was established to temporarily supplement commercial paper borrowings, as needed.

In addition to funding the working capital needs of its diversified businesses primarily through its commercial paper program, Progress Energy can issue long-term debt to fund the capital requirements of Progress Fuels.

Cash Flow From Operating Activities

Florida Progress' cash provided by operations in 2004 of $611 million decreased $31 million compared with 2003 due primarily to storm costs at PEF and an increase in inventory levels, partially offset by recovery of previously under recovered fuel costs at PEF. PEF's operating cash flow increased by $85 million to $533 million in 2004, due primarily to higher net income, an increase in deferred taxes from the restoration costs and casualty losses from the hurricanes for tax purposes and recovery of previously under recovered fuel costs, largely offset by storm costs.

Florida Progress' cash provided by operations in 2003 of $642 million decreased $24 million compared with 2002 due primarily to increased deferred fuel costs at PEF. PEF's operating cash flow increased by $29 million to $448 million in 2003, due primarily to changes in working capital, partially offset by increased deferred fuel costs as a result of rising prices.

Cash Flow From Investing Activities

Cash requirements of Florida Progress used in investing activities during 2004 of $372 million decreased $544 million when compared with 2003. The decrease was due primarily to diversified property asset sales, lower diversified property additions and lower utility property additions in 2004.

Cash requirements of Florida Progress used in investing activities during 2003 of $916 million increased $274 million when compared with 2002. The increase was due primarily to diversified property additions in 2003.

PEF's capital expenditures, including nuclear fuel additions, totaled $492 million and $577 million for 2004 and 2003, respectively. These expenditures are primarily for transmission and distribution assets and generating facilities necessary to meet the needs of the utility's growing customer base. See Note 8D for a discussion of expected impacts on future capital expenditures due to changes in PEF's capitalization policy.

In planning for its future generation needs, PEF develops a forecast of annual demand for electricity, including a forecast of the level and duration of peak demands during the year. These forecasts have historically been developed using a 15% reserve margin. The reserve margin is the difference between a company's net system generating capacity and the maximum demand on the system. In December 1999, the FPSC approved a joint proposal by PEF, Florida Power & Light and Tampa Electric Company to increase the reserve margin to 20% by 2004.

In response, PEF constructed a second generating unit at the Hines site. Hines Unit 2 was placed into service in December 2003. Hines Unit 2 is the same combined-cycle technology as Hines Unit 1 and has a summer generating capacity of approximately 516 MW. In addition, PEF has begun construction of a third unit and has received approval to begin construction of a fourth unit at the Hines Energy Complex.

Diversified business property additions for 2004 and 2003 were $203 million and $424 million, respectively. These capital expenditures have been primarily for the expansion of the Company's natural gas operations.

During 2004, sales of subsidiaries and other investments primarily included proceeds from the sale of Railcar Ltd., assets of approximately $75 million and approximately $251 million from the sale of natural gas assets in the Forth Worth basin of Texas. The Company used the proceeds from these sales to reduce indebtedness and pay dividends to Progress Energy.

The Company received net proceeds of approximately $97 million in October 2003 for the sale of its Mesa gas properties located in Colorado. Proceeds were primarily used to reduce short-term debt.

See Note 20 for a discussion of the effects of compliance with environmental laws and related estimated capital expenditures.

Cash Flow From Financing Activities

Net cash (used in) provided by financing activities for the three years ending December 31, 2004, 2003 and 2002 for the Company were $(237) million, $267 million and $5 million, respectively. Net cash (used in) provided by financing activities for the three years ending December 31, 2004, 2003 and 2002 for PEF were $(35) million, $124 million and $114 million, respectively. See Note 12 for details of debt and credit facilities.

In addition to the financing activities discussed under "Overview," the financing activities of the Company and PEF included:

2005

- In February 2005, PEF used proceeds from money pool borrowings to pay off $55 million of RCA loans and in January 2005, PEF used proceeds from the issuance of commercial paper to pay off $170 million of RCA loans.

2004

- During the fourth quarter of 2004, PEF borrowed a net total of $55 million under its long-term revolving credit facility. In addition, PEF borrowed $170 million under its short-term credit facility. The borrowed funds were used to pay off maturing commercial paper and for other cash needs.

- The following table summarizes the Company's credit facilities as of December 31, 2004:

(in millions) Description	Total	Outstanding	Available
364-Day (expiring 3/29/05)	$ 200	$ 170	$ 30
3-Year (expiring 4/01/06)	200	55	145
Less: amounts reserved(a)			(123)
Total credit facilities	$ 400	$ 225	$ 52

(a) To the extent amounts are reserved for commercial paper outstanding, they are not available for additional borrowings.

- On July 1, 2004, PEF paid at maturity $40 million 6.69% Medium-Term Notes Series B with commercial paper proceeds and cash from operations.

- On March 30, 2004, PEF extended its $200 million 364-day line of credit. The line of credit will expire on March 29, 2005.

- On February 9, 2004, Progress Capital Holdings, Inc. paid at maturity $25 million 6.48% medium term notes with available cash from operations.

2003

- 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 Capital Holdings, Inc., paid at maturity $58 million in medium-term notes.

2002

- PEF issued and redeemed $241 million in pollution control obligations and paid at maturity $30 million in medium-term notes.

- Progress Capital Holdings, Inc., paid at maturity $50 million in medium-term notes.

Credit Facilities

At December 31, 2004, PEF had committed lines of credit and outstanding balances as shown under "Financing Activities." The credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities.

PEF's financial policy precludes issuing commercial paper in excess of its supporting lines of credit. At December 31, 2004, PEF had $123 million of commercial paper outstanding, and an additional $225 million drawn directly from the credit facilities, leaving $52 million available for issuance or drawdown. In addition, PEF has requirements to pay minimal annual commitment fees to maintain its credit facilities. At December 31, 2003, PEF did not have any commercial paper outstanding. PEF expects to continue to use commercial paper issuances as a source of liquidity.

The credit facilities include a defined maximum total debt-to-total capital ratio (leverage) and coverage ratios. PEF is in compliance with these covenants at December 31, 2004. See Note 12 for a discussion of the credit facilities' financial covenants, material adverse change clause provisions and cross-default provisions. At December 31, 2004, the calculated ratios for PEF, pursuant to the terms of the agreements, are as disclosed in Note 12.

PEF has an uncommitted bank bid facility authorizing it to borrow and re-borrow, and have loans outstanding at any time up to $100 million. At December 31, 2004, there were no outstanding loans against these facilities. PEF currently has on file registration statements under which it can issue an aggregate of $750 million of various long-term debt securities.

PEF can issue First Mortgage Bonds under its First Mortgage Bond indenture. At December 31, 2004, PEF could issue up to $3.7 billion based on property additions and $176 million based upon retirements.

Credit Rating Matters

The major credit rating agencies have currently rated the Company's securities as follows:

	Moody's Investors Service	Standard & Poor's
Progress Energy Florida, Inc.		
Corporate credit/issuer rating	Not Applicable	BBB
Commercial paper	P-2	A-3
Senior secured debt	A2	BBB
Senior unsecured debt	A3	BBB
FPC Capital I		
Preferred stock*	Baa2	BB+
Progress Capital Holdings, Inc.		
Senior unsecured debt*	Baa1	BBB-

*Guaranteed by Florida Progress Corporation

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, the Company monitors its financial condition as well as market conditions that could ultimately affect its credit ratings.

The Company and its subsidiaries' debt indentures and credit agreements do not contain any "ratings trigger" which would cause the acceleration of interest and principal payments in the event of a ratings downgrade. However, a ratings downgrade could increase our borrowing costs. See the "Risk Factors" section of this Form 10-K.

On October 19, 2004, S&P changed Progress Energy's outlook from stable to negative. S&P cited the uncertainties regarding the timing of the recovery of hurricane costs, the Company's debt reduction plans and the IRS audit of the Company's Earthco synthetic fuels facilities as the reasons for the change in outlook. On October 25, 2004, S&P reduced the short-term debt rating of PEF to A-3 from A-2, as a result of their change in outlook discussed above.

On October 20, 2004, Moody's changed its outlook for Progress Energy from stable to negative and placed the ratings of PEF under review for possible downgrade.

Moody's cited the following reasons for its change in the outlook for Progress Energy: financial ratios that are weak for its current rating category; rising O&M, including pension, benefit and insurance costs; and delays in executing its deleveraging plan. With respect to PEF, Moody's cited declining cash flow coverage and rising leverage over the last several years, expected funding needs for a large capital expenditure program, risks with regard to its upcoming 2005 rate case and the timing of hurricane cost recovery as reasons for putting its ratings under review.

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

The changes by S&P and Moody's do not trigger any debt or guarantee collateral requirements, nor do they have any material impact on the overall liquidity of PEF. To date, PEF's access to the commercial paper markets has not been materially impacted by the rating agencies' actions. However, the changes have increased the interest rate incurred on its short-term borrowings by 0.25% to 0.875%.

Due to the lower short-term rating issued by Moody's and S&P, PEF borrows under its revolving credit facilities instead of issuing commercial paper due to the difference in investor demand for lower-rated commercial paper. While the cost of borrowing under its revolving credit facilities is higher than commercial paper, it provides the same amount of liquidity.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

The Company and PEF's off-balance sheet arrangements and contractual obligations are described below. See Note 21 for information on the Company's and PEF's contractual obligations at December 31, 2004.

Guarantees

At December 31, 2004, Progress Fuels had issued guarantees on behalf of third parties with a maximum exposure of approximately $10 million. These guarantees support synthetic fuel operations.

Market Risk and Derivatives

The Company and PEF, are exposed to various risks related to changes in market conditions. The Company has a risk management committee that is chaired by the Chief Financial Officer and 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.

The Company manages its market risk in accordance with its established risk management policies, which may include entering into various derivative transactions.

The Company and PEF 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 16 and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

New Accounting Standards

See Note 2 to the Financial Statements for a discussion of the anticipated impact of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Florida Progress

Market risk represents the potential loss arising from adverse changes in market rates and prices. Florida Progress is exposed to certain market risks, including interest rate risk, marketable securities price risk and commodity price risk. The Company manages its market risk in accordance with its established risk management policies, which may include entering into various derivative transactions.

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

Interest Rate Risk

Florida Progress is exposed to risk associated with changes in interest rates with respect to its long-term debt. The Company manages its interest rate risks through the use of a combination of fixed and variable rate debt. Variable rate debt has rates that adjust in periods ranging from daily to monthly. Interest rate derivative instruments may be used to adjust interest rate exposures and to protect against adverse movements in rates.

The following tables provide information at December 31, 2004 and 2003, about the Company's interest rate risk sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed long-term debt and the FPC obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of the Company's interest rate risk sensitive instruments based on quoted market prices for these or similar issues.

December 31, 2004	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value December 31, 2004
(Dollars in millions)								
Fixed rate long-term debt	$ 49	$ 108	$ 124	$ 127	–	$ 1,400	$ 1,808	$ 1,938
Average interest rate	6.63%	6.97%	6.79%	6.72%	–	5.65%	5.91%	
Variable rate long-term debt	–	$ 55	–	–	–	$ 241	$ 296	$ 296
Average interest rate	–	2.95%	–	–	–	1.67%	1.91%	
FPC mandatorily redeemable securities of Trust	–	–	–	–	–	$ 309	$ 309	$ 312
Fixed rate	–	–	–	–	–	7.10%	7.10%	
Unsecured note with parent	–	–	–	–	–	$ 500	$ 500	$ 575
Average interest rate	–	–	–	–	–	6.45%	6.45%	

December 31, 2003	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value December 31, 2003
(Dollars in millions)								
Fixed rate long-term debt	$ 68	$ 49	$ 109	$ 124	$ 127	$ 1,398	$ 1,875	$ 2,007
Average interest rate	6.61%	6.66%	6.96%	6.78%	6.72%	5.65%	5.93%	
Variable rate long-term debt	–	–	–	–	–	$ 241	$ 241	$ 241
Average interest rate	–	–	–	–	–	1.04%	1.04%	
FPC mandatorily redeemable securities of Trust	–	–	–	–	–	$ 309	$ 309	$ 313
Fixed rate	–	–	–	–	–	7.10%	7.10%	
Unsecured note with parent	–	–	–	–	–	$ 500	$ 500	$ 544
Average interest rate	–	–	–	–	–	6.43%	6.43%	

Marketable Securities Price Risk

Florida Progress, through PEF, is exposed to fluctuations in the return on marketable securities with respect to its nuclear decommissioning trust funds. PEF maintains trust funds, as required by the Nuclear Regulatory Commission, to fund certain costs of decommissioning its 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, 2004 and 2003, the fair values of these funds were approximately $463 million and $433 million, respectively. The Company actively monitors its portfolio by benchmarking the performance of its 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 Company's 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 the earnings of the Company.

Commodity Price Risk

The Company and PEF 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 its ownership of energy-related assets. The Company's and PEF's exposure to these fluctuations is significantly limited by the cost-based regulation of PEF. The FPSC allows PEF to recover certain fuel and purchased power costs to the extent the FPSC 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. See Note 16 to the Financial Statements for additional information with regard to the Company's and PEF's commodity contracts and use of derivative financial instruments.

In 2004, PEF entered into derivative instruments related to its exposure to price fluctuations on fuel oil purchases. At December 31, 2004, the fair values of these 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. These instruments receive regulatory accounting treatment. Gains are recorded in regulatory liabilities and losses are recorded in regulatory assets.

Progress Fuels uses natural gas hedging instruments to manage a portion of the market risk associated with fluctuations in the future sales price of Progress Fuels' natural gas. In addition, the Company may from time to time engage in limited economic hedging activity using natural gas and electricity financial instruments.

The Company performs sensitivity analysis to estimate its exposure to the market risk of its commodity positions. The Company excludes the impact of derivative commodity instruments which are recovered through cost-based regulation of PEF from this analysis. A hypothetical 10% increase or decrease in quoted market prices in the near term on its derivative commodity instruments would not have had a material effect on the Company's consolidated financial position, results of operations or cash flows as of December 31, 2004.

PEF

The information required by this item is incorporated herein by reference to the Florida Progress Quantitative and Qualitative Disclosures About Market Risk insofar as it relates to PEF.

The following tables provide information at December 31, 2004 and 2003, about PEF's interest rate risk sensitive instruments.

December 31, 2004	**2005**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**	**Fair Value December 31, 2004**
(Dollars in millions)								
Fixed rate long-term debt	**$ 48**	**$ 48**	**$ 89**	**$ 82**	**–**	**$ 1,400**	**$ 1,667**	**$ 1,784**
Average interest rate	**6.72%**	**6.76%**	**6.80%**	**6.87%**	**–**	**5.65%**	**5.83%**	
Variable rate long-term debt	**–**	**$ 55**	**–**	**–**	**–**	**$ 241**	**$ 296**	**$ 296**
Average interest rate	**–**	**2.95%**	**–**	**–**	**–**	**1.67%**	**1.91%**	

December 31, 2003	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value December 31, 2003
(Dollars in millions)								
Fixed rate long-term debt	$ 43	$ 48	$ 48	$ 89	$82	$ 1,399	$ 1,709	$ 1,820
Average interest rate	6.69%	6.72%	6.76%	6.80%	6.87%	5.65%	5.85%	
Variable rate long-term debt	–	–	–	–	–	$ 241	$ 241	$ 241
Average interest rate	–	–	–	–	–	1.04%	1.04%	

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following consolidated financial statements, supplementary data and consolidated financial statement schedules are included herein:

Report of Independent Registered Public Accounting Firm	38
Consolidated Financial Statements – Florida Progress Corporation:	
Consolidated Statements of Income for the Years Ended December 31, 2004, 2003 and 2002	39
Consolidated Balance Sheets at December 31, 2004 and 2003	40-41
Consolidated Statements of Cash Flows for the Years Ended December 31, 2004, 2003 and 2002	42
Consolidated Statements of Common Equity for the Years Ended December 31, 2004, 2003 and 2002	43
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2004, 2003 and 2002	43
Financial Statements – Florida Power Corporation d/b/a Progress Energy Florida, Inc.:	
Statements of Income for the Years Ended December 31, 2004, 2003 and 2002	44
Balance Sheets at December 31, 2004 and 2003	445-46
Statements of Cash Flows for the Years Ended December 31, 2004, 2003 and 2002	47
Statements of Common Equity for the Years Ended December 31, 2004, 2003 and 2002	48
Statements of Comprehensive Income for the Years Ended December 31, 2004, 2003 and 2002	48
Notes to Financial Statements:	
Note 1 – Organization and Summary of Significant Accounting Policies	49
Note 2 – Impact of New Accounting Standards	54
Note 3 – Hurricane-Related Costs	55
Note 4 – Divestitures	55
Note 5 – Acquisitions and Business Combinations	57
Note 6 – Property, Plant and Equipment	58
Note 7 – Current Assets	61
Note 8 – Regulatory Matters	61
Note 9 – Goodwill and Other Intangible Assets	64
Note 10 – Impairment of Long-Lived Assets and Investments	65
Note 11 – Equity	65
Note 12 – Debt and Credit Facilities	68
Note 13 – Fair Value of Financial Instruments	70
Note 14 – Income Taxes	70
Note 15 – Benefit Plans	73
Note 16 – Risk Management Activities and Derivatives Transactions	76
Note 17 – Related Party Transactions	78
Note 18 – Financial Information by Business Segment	79
Note 19 – Other Income and Other Expense	81
Note 20 – Environmental Matters	82
Note 21 – Commitments and Contingencies	85
Note 22 – Subsequent Events	92
Note 23 – Oil and Gas Producing Activities (Unaudited)	93
Note 24 – Quarterly Financial Data (Unaudited)	95
Report of Independent Registered Public Accounting Firm on Financial Statement Schedules	99
Financial Statement Schedules for the Years Ended December 31, 2004, 2003 and 2002:	
Schedule II – Valuation and Qualifying Accounts – Florida Progress Corporation	98
Schedule II – Valuation and Qualifying Accounts – Florida Power Corporation d/b/a Progress Energy Florida, Inc.	99

All other schedules have been omitted as not applicable or not required or because the information required to be shown is included in the Financial Statements or the accompanying Notes to the Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARDS OF DIRECTORS OF FLORIDA PROGRESS CORPORATION AND FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.:

We have audited the accompanying consolidated balance sheets of Florida Progress Corporation and its subsidiaries (Florida Progress) and the accompanying balance sheets of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) as of December 31, 2004 and 2003, and the related Florida Progress consolidated statements of income, common equity, comprehensive income and cash flows and the related PEF statements of income, common equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the respective 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. Florida Progress and PEF are not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Florida Progress' and PEF's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Florida Progress and of PEF, respectively, at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1 and 6D to the financial statements, in 2003, Florida Progress and PEF adopted Statement of Financial Accounting Standards No. 143.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2005

FLORIDA PROGRESS CORPORATION
CONSOLIDATED STATEMENTS of INCOME

(in millions) Years ended December 31	2004	2003	2002
Operating Revenues			
Utility	$ 3,525	$ 3,152	$ 3,062
Diversified business	2,410	1,856	1,438
Total Operating Revenues	5,935	5,008	4,500
Operating Expenses			
Utility			
Fuel used in electric generation	1,175	870	834
Purchased power	567	566	515
Operation and maintenance	630	640	591
Depreciation and amortization	281	307	295
Taxes other than on income	254	241	228
Diversified business			
Cost of sales	2,127	1,639	1,343
Depreciation and amortization	112	92	66
Impairment of goodwill and long-lived assets	8	15	281
(Gain)/loss on the sale of assets	(54)	1	–
Other	134	132	94
Total Operating Expenses	5,234	4,503	4,247
Operating Income	701	505	253
Other Income (Expense)			
Interest income	5	2	7
Other, net	1	(8)	(20)
Total Other Income (Expense)	6	(6)	(13)
Interest Charges			
Interest charges	183	169	186
Allowance for borrowed funds used during construction	(3)	(6)	(3)
Total Interest Charges, Net	180	163	183
Income from Continuing Operations before Income Tax and Minority Interest	527	336	57
Income Tax Expense (Benefit)	70	(110)	(173)
Income from Continuing Operations before Minority Interest	457	446	230
Minority Interest, net of tax	(17)	3	–
Income from Continuing Operations	474	443	230
Discontinued Operations, Net of Tax:			
Net gain on disposal of discontinued operations, (net of applicable income tax expenses of $0, $2 and $3, respectively)	–	4	5
Net Income	$ 474	$ 447	$ 235

See Notes to Financial Statements.

FLORIDA PROGRESS CORPORATION
CONSOLIDATED BALANCE SHEETS (Continued)

(in millions) December 31	2004	2003
Assets		
Utility Plant		
Utility plant in service	$ 8,387	$ 8,155
Accumulated depreciation	(2,978)	(2,877)
Utility plant in service, net	5,409	5,278
Held for future use	8	8
Construction work in progress	420	292
Nuclear fuel, net of amortization	45	69
Total Utility Plant, Net	5,882	5,647
Current Assets		
Cash and cash equivalents	29	27
Receivables	649	618
Receivables from affiliated companies	40	44
Deferred income taxes	68	60
Inventory	518	449
Deferred fuel cost	89	204
Assets held for sale	–	75
Prepayments and other current assets	35	48
Total Current Assets	1,428	1,525
Deferred Debits and Other Assets		
Regulatory assets	524	126
Debt issuance costs	30	33
Nuclear decommissioning trust funds	463	433
Diversified business property, net	776	841
Miscellaneous other property and investments	95	90
Other assets and deferred debits	488	498
Total Deferred Debits and Other Assets	2,376	2,021
Total Assets	$ 9,686	$ 9,193

FLORIDA PROGRESS CORPORATION
CONSOLIDATED BALANCE SHEETS (Concluded)

(in millions) December 31	2004	2003
Capitalization and Liabilities		
Common Stock Equity		
Common stock without par value	$ 1,712	$ 1,699
Retained earnings	976	842
Accumulated other comprehensive loss	(7)	(17)
Total Common Stock Equity	2,681	2,524
Preferred Stock of Subsidiaries - Not Subject to Mandatory Redemption	34	34
Minority Interest	32	30
Long-Term Debt, Affiliate, Net	809	809
Long-Term Debt, Net	2,052	2,045
Total Capitalization	5,608	5,442
Current Liabilities		
Current portion of long-term debt	49	68
Accounts payable	445	413
Payables to affiliated companies	71	68
Notes payable to affiliated companies	431	636
Taxes accrued	81	33
Short-term obligations	293	–
Customer deposits	135	127
Other current liabilities	364	294
Total Current Liabilities	1,869	1,639
Deferred Credits and Other Liabilities		
Noncurrent income tax liabilities	63	47
Accumulated deferred investment tax credits	36	42
Regulatory liabilities	1,362	1,315
Asset retirement obligations	358	339
Accrued pension and other benefits	229	218
Other liabilities and deferred credits	161	151
Total Deferred Credits and Other Liabilities	2,209	2,112
Commitments and Contingencies (Notes 20 and 21)		
Total Capitalization and Liabilities	$ 9,686	$ 9,193

See Notes to Financial Statements.

FLORIDA PROGRESS CORPORATION
CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	2004	2003	2002
Operating Activities			
Net income	$ 474	$ 447	$ 235
Adjustments to reconcile net income to net cash provided by operating activities:			
Net gain on disposal of discontinued operations	–	(4)	(5)
Net (gain) loss on sale of operating assets	(54)	1	–
Impairment of goodwill and long-lived assets	8	15	281
Depreciation and amortization	421	405	386
Deferred income taxes and investment tax credits, net	(7)	(134)	(239)
Deferred fuel cost (credit)	37	(167)	(22)
Cash provided/(used) by changes in operating assets and liabilities:			
Receivables	59	(75)	(34)
Receivables from affiliated companies	9	14	(15)
Inventory	(87)	46	(40)
Prepayments and other current assets	(118)	(47)	3
Accounts payable	(39)	101	53
Accounts payable to affiliated companies	4	(27)	(29)
Other current liabilities	125	71	29
Changes in regulatory assets and liabilities	(262)	(22)	9
Other	41	18	54
Net Cash Provided by Operating Activities	611	642	666
Investing Activities			
Utility property additions	(482)	(526)	(535)
Diversified business property additions	(203)	(424)	(154)
Nuclear fuel additions	–	(51)	–
Net contributions to nuclear decommissioning trust	–	–	12
Acquisition, net of cash acquired	–		(17)
Proceeds from sale of subsidiaries and investments	336	100	35
Other	(23)	(15)	17
Net Cash Used in Investing Activities	(372)	(916)	(642)
Financing Activities			
Proceeds from issuance of long-term debt	56	935	236
Net increase (decrease) in short-term obligations	293	(258)	103
Retirement of long-term debt	(68)	(534)	(350)
Net (decrease) increase in intercompany notes	(214)	258	233
Equity contributions from parent	13	168	87
Dividends paid to parent	(340)	(301)	(303)
Other	23	(1)	(1)
Net Cash (Used in) Provided by Financing Activities	(237)	267	5
Net Increase (Decrease) in Cash and Cash Equivalents	2	(7)	29
Cash and Cash Equivalents at Beginning of Year	27	34	5
Cash and Cash Equivalents at End of Year	$ 29	$ 27	$ 34
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year – interest (net of amount capitalized)	$ 187	$ 174	$ 176
income taxes (net of refunds)	$ 5	$ 32	$ 60

See Notes to Financial Statements.

Noncash Activities

- In April 2002 Progress Fuels Corporation received an equity contribution from Progress Energy, Inc., with which it acquired 100% of Westchester Gas Company. In conjunction with the purchase, Progress Energy, Inc. issued approximately $129 million in common stock (See Note 5C).
- In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc. both indirectly wholly owned subsidiaries of Progress Energy, and EPIK Communications, Inc., a wholly owned subsidiary of Odyssey Telecorp, Inc., contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC, a subsidiary of PTC (See Note 5A).

FLORIDA PROGRESS CORPORATION
CONSOLIDATED STATEMENTS of COMMON EQUITY

(in millions) Years ended December 31	2004	2003	2002
Beginning Balance	**$ 2,524**	$ 2,211	$ 2,072
Net income	**474**	447	235
Other comprehensive income (loss)	**10**	(1)	(13)
Equity contribution from parent, net	**13**	168	220
Dividend to parent	**(340)**	(301)	(303)
Ending Balance	**$2,681**	$ 2,524	$ 2,211

FLORIDA PROGRESS CORPORATION
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	2004	2003	2002
Net Income	**$ 474**	$ 447	$ 235
Other Comprehensive Income			
Changes in net unrealized losses on cash flow hedges (net of tax benefit of $7, $7 and $4, respectively)	**(12)**	(13)	(6)
Reclassification adjustment for amounts included in net income (net of tax expense of ($9), ($6) and $0, respectively)	**15**	11	(1)
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 $1, ($3) and $3, respectively)	**(1)**	(3)	(5)
Foreign currency translation and other	**4**	4	(1)
Other Comprehensive Income (loss)	**$ 10**	$ (1)	$ (13)
Comprehensive Income	**$ 484**	$ 446	$ 222

See Notes to Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA
STATEMENTS of INCOME

(in millions) Years ended December 31	2004	2003	2002
Operating Revenues	**$ 3,525**	$ 3,152	$ 3,062
Operating Expenses			
Fuel used in electric generation	**1,175**	870	834
Purchased power	**567**	566	515
Operation and maintenance	**630**	640	591
Depreciation and amortization	**281**	307	295
Taxes other than on income	**254**	241	228
Total Operating Expenses	**2,907**	2,624	2,463
Operating Income	**618**	528	599
Other Income (Expense)			
Interest income	**–**	–	2
Other, net	**5**	7	(7)
Total Other Income (Expense)	**5**	7	(5)
Interest Charges			
Interest charges	**117**	97	109
Allowance for borrowed funds used during construction	**(3)**	(6)	(3)
Total Interest Charges, Net	**114**	91	106
Income before Income Taxes	**509**	444	488
Income Tax Expense	**174**	147	163
Net Income	**335**	297	325
Preferred Stock Dividend Requirement	**2**	2	2
Earnings for Common Stock	**$ 333**	$ 295	$ 323

See Notes to Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA
BALANCE SHEETS (continued)

(in millions) December 31	2004	2003
Assets		
Utility Plant		
Utility plant in service	$ 8,387	$ 8,155
Accumulated depreciation	(2,978)	(2,877)
Utility plant in service, net	5,409	5,278
Held for future use	8	8
Construction work in progress	420	292
Nuclear fuel, net of amortization	45	69
Total Utility Plant, Net	5,882	5,647
Current Assets		
Cash and cash equivalents	12	10
Receivables	266	250
Receivables from affiliated companies	16	7
Deferred income taxes	42	39
Inventory	279	268
Deferred fuel cost	89	204
Prepayments and other current assets	12	5
Total Current Assets	716	783
Deferred Debits and Other Assets		
Regulatory assets	524	126
Debt issuance costs	21	25
Nuclear decommissioning trust funds	463	433
Miscellaneous other property and investments	46	40
Prepaid pension cost	234	220
Other assets and deferred debits	38	6
Total Deferred Debits and Other Assets	1,326	850
Total Assets	$ 7,924	$ 7,280

See Notes to Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA
BALANCE SHEETS (concluded)

(in millions) December 31	2004	2003
Capitalization and Liabilities		
Common Stock Equity		
Common stock, without par value	$ 1,081	$ 1,081
Retained earnings	1,240	1,062
Accumulated other comprehensive loss	–	(4)
Total Common Stock Equity	2,321	2,139
Preferred stock – not subject to mandatory redemption	34	34
Long-term debt, net	1,912	1,904
Total Capitalization	4,267	4,077
Current Liabilities		
Current portion of long-term debt	48	43
Accounts payable	262	161
Payables to affiliated companies	80	75
Notes payable to affiliated companies	178	363
Short-term obligations	293	–
Customer deposits	135	127
Other current liabilities	161	154
Total Current Liabilities	1,157	923
Deferred Credits and Other Liabilities		
Noncurrent income tax liabilities	489	363
Accumulated deferred investment tax credits	35	41
Regulatory liabilities	1,362	1,315
Asset retirement obligations	337	319
Accrued pension and other benefits	197	188
Other liabilities and deferred credits	80	54
Total Deferred Credits and Other Liabilities	2,500	2,280
Commitments and Contingencies (Notes 20 and 21)		
Total Capitalization and Liabilities	$ 7,924	$ 7,280

See Notes to Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA
STATEMENTS of CASH FLOWS

(in millions) Years ended December 31	2004	2003	2002
Operating Activities			
Net income	$ 335	$ 297	$ 325
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	310	314	321
Deferred income taxes and investment tax credits, net	110	(25)	(38)
Deferred fuel cost (credit)	37	(167)	(22)
Cash provided/(used) by changes in operating assets and liabilities:			
Receivables	(20)	(7)	2
Receivables from affiliated companies	(8)	36	(29)
Inventory	(27)	(33)	(46)
Prepayments and other current assets	(8)	–	(1)
Accounts payable	13	12	(3)
Payables to affiliated companies	14	(7)	(116)
Other current liabilities	11	35	18
Regulatory assets and liabilities	(262)	(22)	9
Other	28	15	(1)
Net Cash Provided by Operating Activities	533	448	419
Investing Activities			
Property additions	(492)	(526)	(535)
Nuclear fuel additions	–	(51)	
Net contributions to nuclear decommissioning trust		–	12
Other	(4)	(1)	6
Net Cash Used in Investing Activities	(496)	(578)	(517)
Financing Activities			
Proceeds from issuance of long-term debt	56	935	236
Net increase (decrease) in short-term obligations	293	(258)	103
Retirement of long-term debt	(43)	(476)	(278)
Net increase (decrease) in intercompany notes	(185)	126	358
Dividends paid to parent	(155)	(203)	(303)
Dividends paid on preferred stock	(2)	(2)	(2)
Other	1	2	–
Net Cash (Used in) Provided by Financing Activities	(35)	124	114
Net Increase (Decrease) in Cash and Cash Equivalents	2	(6)	16
Cash and Cash Equivalents at Beginning of Year	10	16	–
Cash and Cash Equivalents at End of Year	$ 12	$ 10	$ 16
Supplemental Disclosures of Cash Flow Information			
Cash paid during the year – interest (net of amount capitalized)	$ 118	$ 104	$ 106
income taxes (net of refunds)	$ 57	$ 177	$ 173

See Notes to Financial Statements.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA
STATEMENTS of COMMON EQUITY

(in millions) Years ended December 31	**2004**	2003	2002
Beginning Balance	**$ 2,139**	$ 2,048	$ 2,031
Net income	**335**	297	325
Preferred stock dividends at stated rates	**(2)**	(2)	(2)
Other comprehensive income (loss)	**4**	(1)	(3)
Dividends paid to parent	**(155)**	(203)	(303)
Ending Balance	**$ 2,321**	$ 2,139	$ 2,048

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA
STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2004**	2003	2002
Net Income	**$ 335**	$ 297	$ 325
Other Comprehensive Income			
Reclassification of minimum pension liability to regulatory assets (net of tax expense of ($2))	**4**	–	–
Minimum pension liability adjustment (net of tax benefit of $0, $1 and $1, respectively)	**–**	(1)	(3)
Other Comprehensive Income (loss)	**$ 4**	$ (1)	$ (3)
Comprehensive Income	**$ 339**	$ 296	$ 322

See Notes to Financial Statements.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Florida Progress Corporation (the Company or Florida Progress) is a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). The Company became subject to the regulations of PUHCA when it was acquired by CP&L Energy, Inc. in November 2000. CP&L Energy, Inc. subsequently changed its name to Progress Energy, Inc. (Progress Energy or the Parent). Florida Progress' two primary subsidiaries are Florida Power Corporation (Progress Energy Florida or PEF) and Progress Fuels Corporation (Progress Fuels). Effective January 1, 2003, Florida Power Corporation began doing business under the assumed name Progress Energy Florida, Inc. The legal name of the entity has not changed. The current corporate and business unit structure remains unchanged. Throughout the report, the terms utility and regulated will be used to discuss items pertaining to Progress Energy Florida. Diversified business and nonregulated will be used to discuss the subsidiaries of Florida Progress excluding Progress Energy Florida.

B. Basis of Presentation

The financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The financial statements include the financial results of the Company and its majority-owned subsidiaries. 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," 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.

The Financial Statements of the Company and its subsidiaries include the accounts of their majority-owned and controlled subsidiaries. Noncontrolling interests in the 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 net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which the Company does not have control, but has the ability to exercise influence over operating and financial policies (generally 20% – 50% 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 19). These equity method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the Company has equity method investments of approximately $11 million and $12 million, respectively.

Certain investments in debt and equity securities that have readily determinable market values, and for which the Company does not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants. The fair value of these trust funds was $463 million and $433 million at December 31, 2004 and 2003, respectively.

Other investments are stated principally at cost. These cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the Company has approximately $12 million and $13 million, respectively, of cost method investments.

The results of operations of the Rail Services segment are reported one month in arrears. During 2003, the Company ceased recording portions of the Energy and Related Services segment operations one month in arrears. The net impact of this action increased net income by $2 million for the year.

Certain amounts for 2003 and 2002 have been reclassified to conform to the 2004 presentation.

C. Consolidation of Variable Interest Entities

Florida Progress and PEF consolidate all voting interest entities in which they own a majority voting interest and all variable interest entities for which they are the primary beneficiary in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN No. 46R). A subsidiary of Florida Progress is the primary beneficiary of and consolidates Colona Synfuel Limited Partnership LLLP (Colona), a synthetic fuel production facility that qualifies for federal tax credits under Section 29 of the Internal Revenue Code. As of December 31, 2004, Colona's total assets were $15 million. None of Florida Progress' consolidated assets are collateral for Colona's obligations.

Florida Progress and PEF have interests in several variable interest entities for which they are not the primary beneficiary. These arrangements include investments in approximately five limited partnerships, limited liability corporations and venture capital funds. The aggregate maximum loss exposure at December 31, 2004, that Florida Progress could be required to record in its consolidated income statement as a result of these arrangements totals approximately $13 million. The aggregate maximum loss exposure at December 31, 2004, that PEF could be required to record in its income statement as a result of these arrangements totals approximately $6 million. The creditors of these variable interest entities do not have recourse to the general credit of Florida Progress or PEF in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

In preparing financial statements that conform with 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 financial statements and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

REVENUE RECOGNITION

PEF recognizes 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. Revenues from sales of synthetic fuel and coal are recognized as products are shipped and title passes. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Lease revenue for dedicated transport and data services is generally billed in advance on a fixed rate basis and recognized over the period the services are provided. Revenues relating 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.

FUEL COST DEFERRALS

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

EXCISE TAXES

PEF collects from customers certain excise taxes levied by the state or local government upon the customer. PEF accounts for excise taxes on a gross basis. For the years ended December 31, 2004, 2003 and 2002, gross receipts tax and franchise taxes of approximately $151 million, $136 million and $132 million, respectively, are included in electric operating revenues and taxes other than on income on the Statements of Income.

INCOME TAXES

Progress Energy and its affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to Florida Progress and PEF in accordance with the Intercompany Income Tax Allocation Agreement (Tax Agreement). The Tax Agreement provides 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. Progress Energy tax benefits not related to acquisition interest expense are allocated to profitable subsidiaries, beginning in 2002, in accordance with a PUHCA order. Except for the allocation of this Progress Energy tax benefit, income taxes are provided as if Florida Progress and PEF filed separate returns.

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax bases 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 AMT 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 (See Note 14).

STOCK-BASED COMPENSATION

The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at the grant date, and accordingly, no compensation expense has been recognized for stock option grants. For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an Amendment of FASB Statement No. 123," the estimated fair value of Progress Energy's stock options is amortized to expense over the options' vesting period. The following table illustrates the effect on net income for Florida Progress Corporation and PEF if the fair value method had been applied to all outstanding and unvested awards in each period:

(in millions) Florida Progress	2004	2003	2002
Net income, as reported	$ 474	$ 447	$ 235
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	3	3	3
Pro forma net income	$ 471	$ 444	$ 232

(in millions) Progress Energy Florida	2004	2003	2002
Net income, as reported	$ 335	$ 297	$ 325
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2	2	2
Pro forma net income	$ 333	$ 295	$ 323

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. PEF capitalizes 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, disposal and decommissioning costs that do not represent ARO's under SFAS No. 143 "Accounting for Asset Retirement Obligations," (SFAS No. 143) are charged to regulatory liabilities.

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, the Company adopted the guidance in SFAS No. 143 to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present value of retirement costs for which the Company has 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.

The adoption of this statement had no impact on the income of PEF, as the effects were offset by the establishment of a regulatory liability pursuant to SFAS No. 71 , "Accounting for the Effects of Certain Types of Regulation" (See Note 8A). The Florida Public Service Commission (FPSC) issued an order to authorize deferral of all prospective effects related to SFAS No. 143 as a regulatory asset or liability (See Note 8A).

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 6A). Pursuant to its rate setting authority, the FPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 8).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In PEF's retail jurisdiction, provisions for nuclear decommissioning costs are approved by 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 Federal Energy Regulatory Commission (FERC).

CASH AND CASH EQUIVALENTS

The Company considers cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with a maturity of three months or less.

INVENTORY

The Company accounts for inventory using the average-cost method. Inventories are valued at the lower of cost or market.

REGULATORY ASSETS AND LIABILITIES

PEF's regulated operations are subject to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," 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, PEF records 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 Balance Sheets as regulatory assets and regulatory liabilities (See Note 8A).

DIVERSIFIED BUSINESS PROPERTY

Diversified business property is stated at cost less accumulated depreciation. If an impairment loss is recognized on an asset, the fair value becomes its new cost basis. The cost of renewals and betterments are capitalized. The cost of repairs and maintenance is charged to expense as incurred. For properties other than natural gas and oil properties, depreciation is computed on a straight-line basis over the estimated useful lives as indicated in Note 6B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

The Company uses the full-cost method to account for its 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 costs to develop proved reserves. Except for costs on 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 the Company's 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 Regulation 210.4-10 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.

UNAMORTIZED 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 PEF are amortized over the applicable life using the straight-line method consistent with ratemaking treatment (See Note 8A).

DERIVATIVES

The Company accounts for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and 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. The Company generally designates 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, the Company will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met (See Note 16).

ENVIRONMENTAL

As discussed in Note 20, the Company accrues environmental remediation liabilities when the criteria for SFAS No. 5, "Accounting for Contingencies," 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 the Company's asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

The Company reviews 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, 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, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. The accounting for impairment of long-lived assets is based on SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

The Company reviews its investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline (See Note 10). The Company considers 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 the Company determines that other-than-temporary decline exists in the value of its investments, it is the Company's 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, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2004, 2003 or 2002.

SUBSIDIARY STOCK TRANSACTIONS

Gains and losses realized as a result of common stock sales by the Company's subsidiaries are recorded in the Company's 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. IMPACT OF NEW ACCOUNTING STANDARDS

FASB STAFF POSITION 106-2, "ACCOUNTING AND DISCLOSURE REQUIREMENTS RELATED TO THE MEDICARE PRESCRIPTION DRUG IMPROVEMENT AND MODERNIZATION ACT OF 2003"

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law. In accordance with guidance issued by the FASB in FASB Staff Position 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003" (FASB Staff Position 106-1), the Company elected to defer accounting for the effects of the Medicare Act due to uncertainties regarding the effects of the implementation of the Medicare Act and the accounting for certain provisions of the Medicare Act. In May 2004, the FASB issued definitive accounting guidance for the Medicare Act in FASB Staff Position 106-2, which was effective for the Company in the third quarter of 2004. FASB Staff Position 106-2 results in the recognition of lower other postretirement benefits (OPEB) costs to reflect prescription drug-related federal subsidies to be received under the Medicare Act. The Company's and PEF's accumulated postretirement benefit obligations as of January 1, 2004 were reduced by approximately $36 million and $35 million, respectively, by the impact of the Medicare Act, and the Company's and PEF's 2004 net periodic cost was lower by approximately $5 million due to the Medicare Act.

STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 123 (REVISED 2004), "SHARE-BASED PAYMENT" (SFAS NO. 123R)

In December 2004, the FASB Issued SFAS No. 123R, which revises SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) and supersedes Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." The key requirement of SFAS No. 123R is that the cost of share-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. Previously, entities could elect to continue accounting for such awards at their grant date intrinsic value under APB Opinion No. 25, and the Company made that election. The intrinsic value method resulted in the Company and PEF recording no compensation expense for stock options granted to employees (See Note 11B).

SFAS No. 123R will be effective for the Company on July 1, 2005. The Company intends to implement the standard using the required modified prospective method. Under that method, the Company will record compensation expense under SFAS No. 123R for all awards it grants after July 1, 2005, and it will record compensation expense (as previous awards continue to vest) for the unvested portion of previously granted awards that remain outstanding at July 1, 2005. In 2004, Progress Energy made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued. The Company and PEF expect to record less than $1 million of pre-tax expense for stock options in 2005.

PROPOSED FASB INTERPRETATION OF SFAS 109, "ACCOUNTING FOR INCOME TAXES"

In July 2004, the FASB stated that it plans to issue an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes," that would address the accounting for uncertain tax positions. The FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits.

3. HURRICANE-RELATED COSTS

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of the PEF's service territory during the third quarter of 2004. As of December 31, 2004, restoration costs of PEF's systems from hurricane-related damage was estimated at $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions. As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Storm reserve costs of $13 million were attributable to wholesale customers. PEF has received approval from the FERC to amortize these costs consistent with recovery of such amounts in wholesale rates. PEF continues to review the restoration cost invoices received. Given that not all invoices have been received as of December 31, 2004, PEF will update its petition with the FPSC upon receipt and audit of all actual charges incurred. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005.

On November 17, 2004, the Citizens of the State of Florida, by and through Harold McLean, Public Counsel, and the Florida Industrial Power Users Group (FIPUG), (collectively, Joint Movants), filed a Motion to Dismiss PEF's petition to recover the $252 million in storm costs. On November 24, 2004, PEF responded in opposition to the motion, which was also the FPSC staff's position in its recommendation to the Commission on December 21, 2004 that it should deny the Motion to Dismiss. On January 4, 2005, the Commission ruled in favor of PEF and denied joint Movant's Motion to Dismiss.

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period (See Note 8B).

4. DIVESTITURES

A. Sale of Natural Gas Assets

In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd., an indirectly wholly owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Fuels 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 the Company's 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.

B. Divestiture of Synthetic Fuel Partnership Interests

In June 2004, the Company through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 Company's book value of the interests sold totaled approximately $3 million. The Company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007 and approximately $8 million through the second quarter of 2008. 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.

C. Railcar Ltd. Divestiture

In December 2002, the Progress Energy Board of Directors adopted a resolution approving the sale of Railcar Ltd., a subsidiary included in the Rail Services segment. An estimated pre-tax impairment of $67 million on assets held for sale was recognized in December 2002 to write-down the assets to fair value less costs to sell. This impairment has been included in impairment of long-lived assets in the Consolidated Statements of Income (See Note 10). In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc., and the transaction closed in February 2004. Proceeds from the sale were approximately $82 million before transaction costs and taxes of approximately $13 million. In July 2004, the Company sold the remaining assets classified as held for sale to a third-party for net proceeds of $6 million. The assets of Railcar Ltd. were grouped as assets held for sale and were included in other current assets on the Consolidated Balance Sheets at December 31, 2003, at approximately $75 million, which reflected the Company's estimates of the fair value expected to be realized from the sale of these assets less costs to sell.

D. Mesa Hydrocarbons, Inc., Divestiture

In October 2003, the Company sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Fuels segment. Net proceeds were approximately $97 million and were used to reduce debt. Because the Company utilizes the full-cost method of accounting for its oil and gas operations, the pre-tax gain of approximately $18 million was applied to reduce the basis of the Company's 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.

E. Inland Marine Transportation Divestiture

In July 2001, Progress Energy announced the disposition of the Inland Marine Transportation segment of the Company, which was operated by MEMCO Barge Line, Inc. Inland Marine provided transportation of coal, agricultural and other dry-bulk commodities as well as fleet management services. Progress Energy entered into a contract to sell MEMCO Barge Line, Inc., to AEP Resources, Inc., a wholly-owned subsidiary of American Electric Power. In November 2001, the Company completed the sale of the Inland Marine Transportation segment. The net income of these operations is reported in the Company's Consolidated Statements of Income as discontinued operations.

The net gain on disposal of discontinued operations in the Company's Consolidated Statements of Income for year ended December 31, 2002, represents the after-tax gain from the resolution of approximately $5 million of contingencies in the purchase agreement of the Inland Marine Transportation segment. In connection with the sale, the Company entered into environmental indemnification provisions covering both unknown and known sites. In 2003, the Company reduced the estimate for the environmental accrual by $6 million, which is included as discontinued operations in the Company's Consolidated Statements of Income (See Note 20).

5. ACQUISITIONS AND BUSINESS COMBINATIONS

A. Progress Telecommunications Corporation

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. 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 holds a 55% ownership interest in, and is the parent of, PT LLC. Odyssey holds a combined 45% ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Company's Financial Statements since the transaction date. The minority interest is included in other liabilities and deferred credits in the Consolidated Balance Sheets.

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 certain leasing arrangements of EPIK and finalized its valuation of acquired assets and liabilities. Management considered a number of factors, including valuations and appraisals, when making these determinations. Based on the results of these activities, the preliminary purchase price allocation for EPIK was revised as follows at December 31, 2004: property and equipment – $36 million; other current assets – $7 million; intangible assets – $1 million; current liabilities – $18 million; and exit costs – $4 million. The exit costs consist primarily of lease termination penalties and noncancellable lease payments made after certain leased properties are vacated. The pro forma results of operations reflecting the acquisition would not be materially different then the reported results of operation for 2003 or 2002.

B. Acquisition of Natural Gas Reserves

During 2003, Progress Fuels entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (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 years ended December 31, 2003 and 2002.

C. Westchester Acquisition

In April 2002, Progress Fuels, a subsidiary of Progress Energy, acquired 100% of Westchester Gas Company. During 2004 the name of the company was changed to Winchester Energy Company, Ltd. (Winchester Energy). The acquisition included approximately 215 natural gas-producing wells, 52 miles of intrastate gas pipeline and 170 miles of gas-gathering systems located within a 25-mile radius of Jonesville, Texas, on the Texas-Louisiana border.

The aggregate purchase price of approximately $153 million consisted of cash consideration of approximately $22 million and the issuance of 2.5 million shares of Progress Energy common stock then valued at approximately $129 million. The purchase price included approximately $2 million of direct transaction costs. The final purchase price was allocated to oil and gas properties, intangible assets, diversified business property, net working capital and deferred tax liabilities for approximately $152 million, $9 million, $32 million, $5 million and $45 million, respectively. The $9 million in intangible assets relates to customer contracts (See Note 9).

The acquisition has been accounted for using the purchase method of accounting and, accordingly, the results of operations for Winchester have been included in the Company's Financial Statements since the date of acquisition. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for the year ended December 31, 2002.

6. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

(in millions)	2004	2003
Production plant (7-33 years)	$ 3,818	$ 3,826
Transmission plant (30-75 years)	1,070	1,012
Distribution plant (12-50 years)	3,047	2,894
General plant and other (8-75 years)	452	423
Utility plant in service	$ 8,387	$ 8,155

Substantially all of the electric utility plant is pledged as collateral for the first mortgage bonds of PEF (See Note 12).

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. 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. The composite AFUDC rate for PEF's electric utility plant was 7.8% in 2004, 2003 and 2002.

Depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.3% in 2004, 2003 and 2002. The depreciation provisions related to utility plant were $188 million, $172 million and $162 million in 2004, 2003 and 2002, 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 6D) and regulatory approved expenses (See Note 8 and 20).

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, 2004, 2003 and 2002 were $34 million, $31 million and $32 million, respectively. These amounts are charged to fuel used in electric generation in the Statements of Income.

B. Diversified Business Property

The following is a summary of diversified business property at December 31, with a range of depreciable lives for each:

(in millions)	2004	2003
Equipment (3 – 25 years)	$ 418	$ 283
Land and mineral rights	95	80
Buildings and plants (5 – 40 years)	106	99
Oil and gas properties (units-of-production) (See Note 4A)	336	412
Telecommunications equipment (5 – 20 years)	80	63
Rail equipment (3 – 20 years) (See Note 4C)	35	131
Marine equipment (3 – 35 years)	87	83
Computers, office equipment and software (3 – 10 years)	36	33
Construction work in progress	18	18
Accumulated depreciation	(435)	(361)
Diversified business property, net	$ 776	$ 841

Diversified business depreciation expense was $112 million, $92 million and $66 million for the years ended December 31, 2004, 2003 and 2002, respectively. The synthetic fuel facilities are being depreciated through 2007 when the Section 29 tax credits will expire. Oil and gas depreciation, depletion, and amortization (DD&A) expense was $41 million, $33 million, and $11 million for the years ended December 31, 2004, 2003, and 2002, respectively. DD&A rates per Mcfe were $1.34, $1.31 and $0.92 for the respective years. Oil and gas properties included costs of $55 million at December 2004 which were excluded from capitalized costs being amortized. This includes $48 million in costs related to acquisitions and capitalized interest on probable reserves of $7 million.

C. Joint Ownership of Generating Facilities

PEF is entitled to shares of the generating capability and output of Crystal River Unit No. 3 (CR3) equal to its ownership interest. PEF also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. PEF's share of expenses for the jointly owned facility is included in the appropriate expense category. The co-owner of Intercession City Unit P-11 (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. PEF's ownership interest in CR3 and P11 is listed below with related information at December 31, ($ in millions):

Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
2004				
Crystal River Unit No. 3	**91.78%**	**$ 889**	**$ 443**	**$ 9**
Intercession City Unit P-11	**66.67%**	**22**	**7**	**8**
2003				
Crystal River Unit No. 3	91.78%	$ 875	$ 442	$ 46
Intercession City Unit P-11	66.67%	22	6	6

D. Asset Retirement Obligations

The asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $36 million and $37 million for regulated operations at December 31, 2004 and 2003, respectively. The ongoing expense differences between SFAS No. 143 and regulatory cost recovery are being deferred to the regulatory liability. Funds set aside in PEF's nuclear decommissioning trust fund for the nuclear decommissioning liability totaled $463 million at December 31, 2004 and $433 million at December 31, 2003. Net unrealized gains on the nuclear decommissioning trust fund were included in regulatory liabilities.

PEF's expense recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset removal obligations, which are included in depreciation and amortization expense, were $77 million, $72 million and $68 million in 2004, 2003 and 2002, respectively.

PEF recognizes removal, non-nuclear decommissioning and dismantlement costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 8A). At December 31, 2004, such costs consist of removal costs of $1,005 million, decommissioning costs for nonirradiated areas at nuclear facilities of $61 million and amounts previously collected for dismantlement of fossil generation plants of $144 million. At December 31, 2003, such costs consist of removal costs of $945 million, decommissioning costs for nonirradiated areas at nuclear facilities of $62 million and amounts previously collected for dismantlement of fossil generation plants of $143 million.

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

The Company's nonregulated AROs relate to coal mine operations, synthetic fuel operations and gas production of Progress Fuels Corporation. The related asset retirement costs, net of accumulated depreciation, totaled $10 million and $5 million at December 31, 2004 and 2003, respectively.

The following table shows the changes to the asset retirement obligations. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels.

(in millions)	Regulated	Nonregulated
Asset retirement obligations as of January 1, 2003	$ 303	$ 10
Additions	–	11
Accretion expense	16	1
Deductions	–	(2)
Asset retirement obligations as of December 31, 2003	**319**	**20**
Additions	**–**	**6**
Accretion expense	**18**	**2**
Deductions	**–**	**(7)**
Asset retirement obligations as of December 31, 2004	**$ 337**	**$ 21**

The cumulative effect of initial adoption of this statement related to nonregulated operations was $2 million of pre-tax expense, which is included in other, net on the Company's Consolidated Statements of Income for the year ended December 31, 2003. Pro forma net income has not been presented for prior years because the pro forma application of SFAS No. 143 to prior years would result in pro forma net income not materially different from the actual amounts reported.

E. Insurance

PEF is a member 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, PEF is insured for $500 million at its nuclear plant, CR3. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with a limit of $1.1 billion.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. PEF is insured thereunder, following a twelve-week deductible period, for 52 weeks in the amount of $4.5 million per week at CR3. An additional 71 weeks of coverage is provided at 80% of the above weekly amount. For the current policy period, PEF is subject to retrospective premium assessments of up to approximately $6.5 million with respect to the primary coverage, $5.2 million with respect to the decontamination, decommissioning and excess property coverage, and $5.5 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 U.S. Nuclear Regulatory Commission, PEF'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. PEF is responsible to the extent losses may exceed limits of the coverage described above.

PEF is 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, PEF, as an owner of a nuclear unit, 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), PEF would be subject to pro rata assessments of up to $101 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 $10 million per reactor owned. Congress could possibly approve revisions to the Price Anderson Act during 2005, that could include increased limits and assessments per reactor owned. The final outcome of this matter cannot be predicted at this time.

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 the terrorist acts.

PEF self-insures its transmission and distribution lines against loss due to storm damage and other natural disasters. Pursuant to a regulatory order, PEF is accruing $6 million annually to a storm damage reserve and may defer any losses in excess of the reserve (See Note 3 and 8A).

7. CURRENT ASSETS

RECEIVABLES

At December 31, receivables were comprised of the following:

	Florida Progress		Progress Energy Florida	
(in millions)	**2004**	2003	**2004**	2003
Trade accounts receivable	**$ 438**	$ 410	**$ 195**	$ 187
Unbilled accounts receivable	**93**	135	**66**	59
Notes receivable	**97**	62	**–**	–
Other receivables	**12**	15	7	6
Unbilled other receivables	**28**	11	**–**	–
Allowance for doubtful accounts receivable	**(19)**	(15)	**(2)**	(2)
Total receivables	**$ 649**	$ 618	**$ 266**	$ 250

Income tax receivables and interest income receivables are not included in this classification. These amounts are in prepayments and other current assets on the Consolidated Balance Sheets.

INVENTORY

At December 31, inventory was comprised of the following:

	Florida Progress		Progress Energy Florida	
(in millions)	**2004**	2003	**2004**	2003
Fuel for production	**$ 103**	$ 90	**$ 103**	$ 90
Inventory for sale	**228**	167	**–**	–
Materials and supplies	**187**	192	**176**	178
Total inventory	**$ 518**	$ 449	**$ 279**	$ 268

8. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As a regulated entity, PEF is subject to the provisions of SFAS No. 71. Accordingly, PEF records certain assets and liabilities resulting from the effects of the ratemaking process, which would not be recorded under GAAP for nonregulated entities. The utility's 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 applied to PEF's 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.

PEF has regulatory assets (liabilities) at December 31 as follows:

(in millions)	2004	2003
Deferred fuel cost - current (Note 8B)	$ 89	$ 204
Deferred fuel cost – long-term (Note 8B)	79	–
Storm deferral (Note 3)	291	–
Income taxes recoverable through future rates (Note 14)	49	42
Loss on reacquired debt (Note 1D)	31	33
Other	74	51
Total long-term regulatory assets	524	126
Deferred energy conservation cost - current	(8)	(7)
Non-ARO cost of removal (Note 6D)	(1,210)	(1,150)
Deferred impact of ARO (Note 1D)	(26)	(8)
Net nuclear decommissioning trust unrealized gains (Note 6D)	(99)	(105)
Storm reserve (Note 3)	–	(41)
Other	(27)	(11)
Total long-term regulatory liabilities	(1,362)	(1,315)
Net regulatory assets (liabilities)	$ (757)	$ (992)

Except for portions of deferred fuel and deferred storm costs, all 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. The utility expects to fully recover these assets and refund the liabilities through customer rates under current regulatory practice.

B. Retail Rate Matters

On November 9, 2004, the FPSC approved PEF's under-recovered fuel costs of $156 million for 2004, of which PEF plans to defer $79 million until 2006 to mitigate the impact on customers resulting from the need to also recover hurricane-related costs. Therefore, $79 million of deferred fuel cost has been classified as a long-term asset. As of December 31, 2004, PEF was under-recovered in fuel costs by $168 million. The additional $12 million over and above the $156 million approved by the FPSC will be included in PEF's 2005 fuel filing.

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 the Company's affiliated coal supplier, Progress Fuels Corporation. 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 $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.

PEF RATE CASE SETTLEMENT

The FPSC initiated a rate proceeding in 2001 regarding PEF's future base rates. In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC in April 2002. The Agreement is generally effective from May 2002 through December 2005, provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates.

The Agreement provides that PEF will reduce its retail revenues from the sale of electricity by an annual amount of $125 million. The Agreement also provides that PEF will operate under a Revenue Sharing Incentive Plan (the Plan) through 2005, and thereafter until terminated by the FPSC, that establishes annual revenue caps and sharing thresholds. The Plan provides that retail base rate revenues between the sharing thresholds and the retail base rate revenue caps will be divided into two shares – a 1/3 share to be received by PEF's shareholders, and a 2/3 share to be refunded to PEF's retail customers, provided, however, that for the year 2002 only, the refund to customers was limited to 67.1% of the 2/3 customer share. The retail base rate revenue sharing threshold amounts for 2004, 2003 and 2002 were $1.370 billion, $1.333 billion and $1.296 billion, respectively, and will increase $37 million in 2005. The Plan also provides that all retail base rate revenues above the retail base rate revenue caps established for each year will be refunded to retail customers on an annual basis. For 2002, the refund to customers was limited to 67.1% of the retail base rate revenues that exceeded the 2002 cap. The retail base revenue caps for 2004, 2003 and 2002 were $1.430 billion, $1.393 billion and $1.356 billion, respectively, and will increase $37 million in 2005. Any amounts above the retail base revenue caps will be refunded 100% to customers. At December 31, 2004, $9 million has been accrued and will be refunded to retail customers by March 2005. The 2003 revenue sharing amount was $18 million, and was refunded to customers by April 30, 2004. Approximately $5 million was originally returned in March 2003 related to 2002 revenue sharing. However, in February 2003, the parties to the Agreement filed a motion seeking an order from the FPSC to enforce the Agreement. In this motion, the parties disputed PEF's calculation of retail revenue subject to refund and contended that the refund should be approximately $23 million. In July 2003, the FPSC ruled that PEF must provide an additional $18 million to its retail customers related to the 2002 revenue sharing calculation. PEF recorded this refund in the second quarter of 2003 as a charge against electric operating revenue and refunded this amount by October 2003.

The Agreement also provides that beginning with the in-service date of PEF's Hines Unit 2 and continuing through December 2005, PEF will be allowed to recover through the fuel cost recovery clause a return on average investment and depreciation expense for Hines Unit 2, to the extent such costs do not exceed the Unit's cumulative fuel savings over the recovery period. Hines Unit 2 is a 516 MW combined-cycle unit that was placed in service in December 2003. In 2004, PEF recovered $36 million through this clause related to Hines Unit 2.

In addition, PEF suspended retail accruals on its reserves for nuclear decommissioning and fossil dismantlement through December 2005. Additionally, for each calendar year during the term of the Agreement, PEF will record a $63 million depreciation expense reduction, and may at its option, record up to an equal annual amount as an offsetting accelerated depreciation expense. No accelerated depreciation expense was recorded during 2004 and 2003. In addition, PEF is authorized, at its discretion, to accelerate the amortization of certain regulatory assets over the term of the Agreement.

Under the terms of the Agreement, PEF agreed to continue the implementation of its four-year Commitment to Excellence Reliability Plan and expected to achieve a 20% improvement in its annual System Average Interruption Duration Index by no later than 2004. If this improvement level was not achieved for calendar years 2004 or 2005, PEF would have provided a refund of $3 million for each year the level is not achieved to 10% of its total retail customers served by its worst performing distribution feeder lines. PEF achieved this improvement level in 2004.

In January 2005, in anticipation of the expiration of its Stipulation and Settlement approved by the FPSC in 2002 to conclude PEF's then-pending rate case, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2006. In its notice, PEF requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. The request for increased base rates is based on the fact that PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines 3 generation facility, extraordinary hurricane damage costs including capital costs which are not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of strong customer growth. On February 7, 2005, the FPSC acknowledged receipt of PEF's notice and authorized minimum filing requirements and testimony to be filed May 1, 2005.

C. Regional Transmission Organizations and Standard Market Design

In 2000, the Federal Energy Regulatory Commission (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 July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access

Transmission Service and Standard Electricity Market Design (SMD NOPR). If adopted as proposed, the rules set forth in the SMD NOPR would have materially altered the manner in which transmission and generation services are provided and paid for. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provided an overview of what the FERC intended to include in a final rule in the SMD NOPR docket. The White Paper retained the fundamental and most protested aspects of SMD NOPR, including mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. The FERC has not yet issued a final rule on SMD NOPR. The Company cannot predict the outcome of these matters or the effect that they may have on the GridFlorida proceedings currently ongoing before the FERC.

The Florida Public Service Commission (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 currently scheduled to be presented at a FPSC workshop on May 25, 2005, with subsequent action by the FPSC to be thereafter determined.

PEF has $4 million invested in GridFlorida related to startup costs at December 31, 2004. PEF expects to recover these startup costs in conjunction with the GridFlorida original structure or in conjunction with any alternate combined transmission structure that emerges.

D. Energy Delivery Capitalization Practice

PEF has reviewed its capitalization policy for its Energy Delivery business unit. That review indicated that in the areas of outage and emergency work not associated with major storms and allocation of indirect costs, PEF should revise the way that it estimates the amount of capital costs associated with such work. PEF has implemented such changes effective January 1, 2005, which include more detailed classification of outage and emergency work and result in more precise estimation and a process of retesting 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 PEF's costs will be capitalized on a going forward basis. PEF estimates that the impact in 2005 will be that approximately $30 million of costs that would have been capitalized under the previous policies will be expensed. Pursuant to SFAS No. 71, PEF has informed the state regulators having jurisdiction over them of this change and that the new estimation process will be implemented effective January 1, 2005. The Company has also requested a method change from the IRS.

9. GOODWILL AND OTHER INTANGIBLE ASSETS

The Company accounts for goodwill and other intangible assets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The changes in the carrying amount of goodwill, by reportable segment, are as follows:

(in millions)	Energy and Related Services	Other	Total
Balance as of January 1, 2003	$ 11	$ –	$ 11
Divestitures	(1)	–	(1)
Acquisition	–	7	7
Balance as of December 31, 2003	**$ 10**	**$ 7**	**$ 17**
Impairment loss	**(8)**	**–**	**(8)**
Purchase accounting adjustment	**–**	**(7)**	**(7)**
Balance as of December 31, 2004	**$ 2**	**$ –**	**$ 2**

In connection with a review of strategic alternatives regarding the Fuels' coal mining business, the Company performed an impairment test of the goodwill of the coal mining business in the fourth quarter of 2004. As a result of the impairment test, the Company recorded an impairment loss of $8 million to write off all of the goodwill of the coal mining business. The Company used a probability-weighted discounted cash flow analysis to perform the assessment.

In December 2003, $7 million in goodwill was acquired based on a preliminary purchase price allocation as part of the Progress Telecommunications Corporation partial acquisition of EPIK and was reported in the Other segment. As discussed in Note 5, the Company 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 Company has $10 million and $9 million of net amortizable intangible assets at December 31, 2004 and 2003, respectively. The Company's intangibles are primarily acquired customer contracts that are amortized over their respective lives. Amortization expense recorded on intangible assets for the years ended December 31, 2004 and 2003, and estimated annual amortization expense for intangible assets for 2004 through 2008 are not material to the results of operations. PEF has no intangible assets at December 31, 2004 or 2003.

10. IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

Effective January 1, 2002, the Company adopted SFAS No. 144, which provides guidance for the accounting and reporting of impairment or disposal of long-lived assets. The statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of." In 2003 and 2002, the Company recorded impairments and other charges of approximately $15 million and $300 million, respectively.

Due to the reduction in coal production at the Kentucky May Coal Mine, the Company evaluated its long-lived assets in 2003. Fair value was determined based on discounted cash flows. As a result of this review, the Company recorded asset impairments of $15 million on a pre-tax basis during the fourth quarter of 2003.

The 2002 amount includes an estimated impairment of assets held for sale of $67 million related to Railcar Ltd., (See Note 4C). In 2002, the Company also initiated an independent valuation study to assess the recoverability of the long-lived assets of PTC. Based on this assessment, the Company recorded asset impairments of $215 million on a pre-tax basis and other charges of $18 million on a pre-tax basis in the third quarter of 2002. This write-down constitutes a significant reduction in the book value of these long-lived assets. The long-lived asset impairments include an impairment of property, plant and equipment, construction work in process and intangible assets. The impairment charge represents the difference between the fair value and carrying amount of these long-lived assets. The fair value of these assets was determined using a valuation study heavily weighted on the discounted cash flow methodology, using market approaches as supporting information.

11. EQUITY

A. Common and Preferred Stock

Common stock at December 31, 2004 and 2003 consisted of the following

(in millions except share data)	2004	2003
Florida Progress		
Common stock without par value, 250,000,000 shares authorized; **98,616,658 shares outstanding in 2004 and 2003**	**$ 1,712**	**$ 1,699**
Progress Energy Florida		
Common stock without par value, 60,000,000 shares authorized; 100 shares outstanding in 2004 and 2003	**$ 1,081**	**$ 1,081**

From time-to-time the Company and its subsidiaries may receive equity contributions from and pay dividends to Progress Energy. The Company received equity contributions from Progress Energy of $13 million, $168 million and $220 million during 2004, 2003 and 2002, respectively. The Company paid dividends to Progress Energy of $340 million, $301 million and $303 million during 2004, 2003 and 2002, respectively.

The authorized capital stock of the Company includes 10 million shares of preferred stock, without par value, including 2 million shares designated as Series A Junior Participating Preferred Stock. No shares of the Company's preferred stock are issued or outstanding.

The authorized capital stock of PEF includes three classes of preferred stock: 4 million shares of Cumulative Preferred Stock, $100 par value; 5 million shares of Cumulative Preferred Stock, without par value; and 1 million shares of Preference Stock, $100 par value. No shares of PEF's Cumulative Preferred Stock, without par value, or Preference Stock are issued or outstanding. All Cumulative Preferred Stock series are without sinking funds and are not subject to mandatory redemption.

Preferred stock outstanding at December 31, 2004 and 2003 consisted of the following (in millions, except share data and par value):

4.00% - 39,980 shares outstanding (redemption price $104.25)	**$**	**4**
4.40% - 75,000 shares outstanding (redemption price $102.00)		**8**
4.58% - 99,990 shares outstanding (redemption price $101.00)		**10**
4.60% - 39,997 shares outstanding (redemption price $103.25)		**4**
4.75% - 80,000 shares outstanding (redemption price $102.00)		**8**
Total Preferred Stock of PEF	**$**	**34**

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

Progress Energy sponsors the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining employees within participating subsidiaries are eligible. Effective January 1, 2002, Florida Progress is a participating subsidiary of 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 stock 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 Progress Energy matching and incentive contributions and/or reinvested dividends.

Florida Progress' 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. The 401(k) common stock share needs are met 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. Florida Progress' matching and incentive cost which was and will be met with shares released from the suspense account totaled approximately $5 million, $4 million and $2 million for the years ended December 31, 2004, 2003 and 2002, respectively. Matching and incentive costs totaled approximately $7 million, $11 million and $10 million for the years ended December 31, 2004, 2003 and 2002, respectively. PEF's matching and incentive cost which was and will be met with shares released from the suspense account totaled approximately $5 million, $4 million and $2 million for the year ended December 31, 2004, 2003 and 2002, respectively. Matching and incentive costs totaled approximately $7 million, $10 million and $9 million for the years ended December 31, 2004, 2003 and 2002, respectively.

STOCK OPTION AGREEMENTS

Pursuant to the Progress Energy's 1997 Equity Incentive Plan and 2002 Equity Incentive Plans as amended and restated as of July 10, 2002, Progress Energy may grant options to purchase shares of common stock to directors, officers and eligible employees. For the years ended December 31, 2004, 2003 and 2002 approximately 28 thousand, 3.0 million and 2.9 million common stock options were granted, respectively. Of these amounts, approximately 1.0 million and 0.8 million options, respectively, were granted to officers and eligible employees of Florida Progress and PEF in 2003 and approximately 0.5 million and 0.4 million options, respectively, were granted in 2002. No stock options were granted to officers and employees of Florida Progress and PEF in 2004. The Company expects to begin expensing stock options on July 1, 2005 by adopting new FASB guidance on accounting for stock-based compensation that was issued (See Note 2). In 2004, however, Progress Energy made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued.

The pro forma information presented in Note 1 regarding net income and earnings per share is required by SFAS No. 148. Under this statement, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The pro forma amounts presented in Note 1 have been determined as if the Company had accounted for its employee stock options under SFAS No. 123.

OTHER STOCK-BASED COMPENSATION PLANS

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

Under the terms of the PSSP, officers and key employees are granted 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's 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 Progress Energy's results as compared to a peer group of utilities. Compensation expense is recognized over the vesting period based on the expected ultimate cash payout and is reduced by any forfeitures.

The RSA program allows Progress Energy to grant shares of restricted common stock to officers and key employees of Progress Energy. 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 and is reduced by any forfeitures.

The total amount expensed by the Company for other stock-based compensation under these plans was $2 million, $9 million and $5 million in 2004, 2003 and 2002, respectively. The total amount expensed by PEF for other stock-based compensation under these plans was $2 million, $7 million and $4 million in 2004, 2003 and 2002, respectively.

C. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss for Florida Progress and PEF at December 31, 2004 and 2003 are as follows:

	Florida Progress		Progress Energy Florida	
(in millions)	**2004**	2003	**2004**	2003
Loss on cash flow hedges	**$ (5)**	$ (9)	**$ –**	$ –
Minimum pension liability adjustments	(7)	(9)	–	(4)
Foreign currency translation and other	**5**	1	**–**	–
Total accumulated other comprehensive loss	$ (7)	$ (17)	**$ –**	$ (4)

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit

At December 31, the Company's (including PEF's) long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2004):

(in millions)	Rate	2004	2003
Progress Energy Florida, Inc.			
First mortgage bonds, maturing 2008-2033	5.60%	**1,330**	1,330
Pollution control obligations, maturing 2018-2027	1.67%	**241**	241
Medium-term notes, maturing 2005-2028	6.76%	**337**	379
Draws on revolving credit agreement, expiring 2006	2.95%	**55**	–
Unamortized premium and discount, net		**(3)**	(3)
		1,960	1,947
Florida Progress Funding Corporation (See Note 17)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2006-2008	6.84%	**140**	165
Unsecured note with parent, maturing 2011	6.45%	**500**	500
Miscellaneous notes		**1**	1
		641	666
Current portion of long-term debt		**(49)**	(68)
Total long-term debt		**$ 2,861**	$ 2,854

In February 2005, PEF used proceeds from money pool borrowings to pay off $55 million of RCA loans and in January 2005, PEF used proceeds from the issuance of commercial paper to pay off $170 million of RCA loans.

At December 31, 2004, PEF had committed lines of credit which are used to support its commercial paper borrowings. The 3-year credit facility is included in long-term debt. The 364-day credit facility is included in short-term obligations and had $170 million of outstanding borrowings at December 31, 2004, at an interest rate of 3.13%. No amount was outstanding under the committed lines of credit at December 31, 2003. PEF is required to pay minimal annual commitment fees to maintain its credit facilities.

The following table summarizes PEF's credit facilities:

(in millions) Description	Total	Outstanding	Available
364-Day (expiring 3/29/05)	$ 200	$ 170	$ 30
3-Year (expiring 4/01/06)	200	55	145
Less: amounts reserved(a)			(123)
Total credit facilities	$ 400	$ 225	$ 52

(a) To the extent amounts are reserved for commercial paper outstanding, they are not available for additional borrowings.

At December 31, 2004, PEF had $123 million of outstanding commercial paper and other short-term debt classified as short-term obligations. The weighted-average interest rate of such short-term obligations at December 31, 2004 was 2.80%. At December 31, 2003, PEF had no outstanding commercial paper and other short-term debt classified as short-term obligations.

The combined aggregate maturities of Florida Progress long-term debt for 2005 through 2008 are approximately, in millions, $49, $163, $124 and $127, respectively. PEF's aggregate maturities of long-term debt for 2005 through 2008 are approximately, in millions, $48, $103, $89 and $82, respectively. There are no long-term debt maturities in 2009 for PEF or Florida Progress.

B. Covenants and Default Provisions

FINANCIAL COVENANTS

PEF's credit line contains various terms and conditions that could affect PEF's ability to borrow under these facilities. These include a maximum debt to total capital ratio, an interest test, a material adverse change clause and a cross-default provision. PEF's credit line requires a maximum total debt to total capital ratio of 65.0%. Indebtedness as defined by the bank agreement includes certain letters of credit and guarantees which are not recorded on the Balance Sheets. At December 31, 2004, PEF's total debt to total capital ratio was 50.8%.

PEF's 364-day and 3-year credit facility have a financial covenant for interest coverage. The covenant requires PEF's EBITDA to interest expense to be at least 3 to 1. For the year ended December 31, 2004, this ratio was 7.93 to 1.

MATERIAL ADVERSE CHANGE CLAUSE

The credit facility of PEF includes a provision under which lenders could refuse to advance funds in the event of a material adverse change (MAC) in the borrower's financial condition.

CROSS-DEFAULT PROVISIONS

PEF's credit lines include cross-default provisions for defaults of indebtedness in excess of $10 million. PEF's cross-default provisions only apply to defaults of indebtedness by PEF and not to other affiliates of PEF. The credit lines of Progress Energy include a similar provision. Progress Energy's cross-default provisions only apply to defaults of indebtedness by Progress Energy and its significant subsidiaries, which includes PEF, Florida Progress, Progress Fuels and Progress Capital.

In the event that either of these cross-default provisions were triggered, the lenders could accelerate payment of any outstanding debt. Any such acceleration would cause a MAC in the respective company's financial condition. Certain agreements underlying the Company's indebtedness also limit the Company's ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

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, 2004, none of PEF's retained earnings were 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 (a) all credits to retained earnings since April 30, 1944, plus (b) all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers amounts from retained earnings to capital surplus. At December 31, 2004, none of PEF's retained earnings was restricted.

PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. On December 31, 2004, PEF's common stock equity was approximately 54.4% of total capitalization.

C. Secured Obligations

PEF's first mortgage bonds are secured by its mortgage indenture. PEF's mortgage constitutes a first lien on substantially all of its fixed properties, subject to certain permitted encumbrances and exceptions. The PEF mortgage also constitutes a lien on subsequently acquired property. At December 31, 2004, PEF had approximately $1.571 billion in aggregate principal amount of first mortgage bonds outstanding including those related to pollution control obligations. The PEF mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

See Note 17 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. Hedging Activities

PEF uses interest rate derivatives to adjust the fixed and variable rate components of its debt portfolio and to hedge cash flow risk of fixed rate debt to be issued in the future. See discussion of risk management and derivative transactions at Note 16.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

At December 31, 2004 and 2003, there were miscellaneous investments, consisting primarily of investments in company-owned life insurance and other benefit plan assets, with carrying amounts of approximately $73 million and $66 million, respectively, included in miscellaneous other property and investments. At PEF, these investments had carrying amounts of $34 million and $33 million at December 31, 2004 and 2003, respectively. The carrying amount of these investments approximates fair value due to the short maturity. The carrying amount of the Company's long-term debt, including current maturities, was $2,910 million and $2,922 million at December 31, 2004 and 2003, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3,121 million and $3,105 million at December 31, 2004 and 2003, respectively. The carrying amount of PEF's long-term debt, including current maturities, was $1,960 million and $1,947 million at December 31, 2004 and 2003, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2,080 million and $2,061 million at December 31, 2004 and 2003, respectively.

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 6D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. 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.

14. INCOME TAXES

Deferred income taxes have been provided 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 PEF 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 utility pursuant to rate orders.

Accumulated deferred income tax assets (liabilities) at December 31 are (in millions):

Florida Progress	2004	2003
Current portion of deferred income tax asset		
Unbilled revenue	$ 35	$ 18
Other	33	42
Net current portion of deferred income tax asset	$ 68	$ 60
Noncurrent deferred income tax asset (liability):		
Accumulated depreciation and property cost differences	$ (400)	$ (359)
Investments	49	(17)
Supplemental executive retirement plans	19	19
Other post-employment benefits (OPEB)	65	64
Other pension plans	(89)	(85)
Goodwill	34	46
Deferred storm costs	(113)	–
Storm damage reserve	–	16
Premium on reacquired debt	(12)	(13)
State NOL carry forward	23	28
Federal and state income tax credit carry forward	494	437
Miscellaneous other temporary differences, net	57	25
Valuation allowance	(27)	(29)
Total noncurrent deferred income tax asset	100	132
Less amount included in other assets and deferred debits	161	172
Net noncurrent deferred income tax liability	$ (61)	$ (40)

Progress Energy Florida	2004	2003
Current portion of deferred income tax asset		
Unbilled revenue	$ 35	$ 18
Other	7	21
Net current portion of deferred income tax asset	$ 42	$ 39
Noncurrent deferred income tax asset (liability):		
Accumulated depreciation and property cost differences	$ (389)	$ (368)
Other post-employment benefits (OPEB)	63	62
Other pension plans	(89)	(85)
Deferred storm costs	(113)	–
Storm damage reserve	–	16
Miscellaneous other temporary differences, net	39	17
Total noncurrent deferred income tax liability	$ (489)	$ (358)

The Company's total deferred income tax liabilities were $997 million and $824 million at December 31, 2004 and 2003, respectively. Total deferred income tax assets were $1,165 million and $1,016 million at December 31, 2004 and 2003, respectively. Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2004 and 2003 include $2 and $7 million, respectively, related to contingent tax liabilities on which the Company accrues interest that would be payable with the related tax amount in future years.

PEF's total deferred income tax liabilities were $620 million and $476 million at December 31, 2004 and 2003, respectively. Total deferred income tax assets were $173 million and $157 million at December 31, 2004 and 2003, respectively. Total noncurrent income tax liabilities on the Balance Sheets at December 31, 2004 and 2003 include none and $5 million, respectively, related to contingent tax liabilities on which the company accrues interest that would be payable with the related tax amount in future years.

The Company's federal income tax credit carry forward at December 31, 2004 consists of $484 million of alternative minimum tax credit with an indefinite carry forward period and $9 million of general business credit with a carry forward period that will begin to expire in 2022. The Company's alternative minimum tax credit carry forward at December 31, 2004 includes $3 million that would be limited if a change in ownership were to occur with respect to certain indirect wholly owned subsidiary companies.

As of December 31, 2004, the Company had a state net operating loss carry forward of $2 million that will begin to expire in 2007.

The Company decreased its valuation allowance during 2004 by $2 million and established additional valuation allowances of $3 million and $5 million during 2003 and 2002, respectively, due to the uncertainty of realizing certain future state tax benefits. The Company decreased its 2004 beginning-of-the-year valuation allowance by $8 million for a change in circumstances related to net operating losses. The Company believes 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.

The Company establishes accruals for certain tax contingencies when, despite the belief that the Company's tax return positions are fully supported, the Company believes that certain positions may be challenged and that it is probable the Company's positions may not be fully sustained. The Company is under continuous examination by the Internal Revenue Service and other tax authorities and accounts for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2004 and 2003, respectively, the Company had recorded $60 million and $56 million of tax contingency reserves, excluding accrued interest and penalties, which are included in current Taxes Accrued on the Consolidated Balance Sheets. At December 31, 2004 and 2003, PEF had recorded $7 million of tax contingency reserves, excluding accrued interest and penalties, which are included in other current liabilities on the Balance Sheets. Considering all tax contingency reserves, the Company does not expect the resolution of these matters to have a material impact on its financial position or result of operations. All tax contingency reserves relate to capitalization and basis issues and do not relate to any potential disallowances of tax credits from synthetic fuel production (See Note 21E).

Reconciliations of the Company's effective income tax rate to the statutory federal income tax rate are:

Florida Progress	**2004**	2003	2002
Effective income tax rate	**13.3%**	(32.6)%	(304.8)%
State income taxes, net of federal benefit	**(6.1)**	(2.5)	(10.3)
AFUDC amortization	**(0.5)**	(0.7)	(4.1)
Federal tax credits	**24.4**	63.5	311.3
Investment tax credit amortization	**1.2**	1.8	11.3
Progress Energy tax allocation benefit	**2.7**	3.8	35.2
Other differences, net	**—**	1.7	(3.6)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Progress Energy Florida	**2004**	2003	2002
Effective income tax rate	**34.2%**	33.1%	33.6%
State income taxes, net of federal benefit	**(3.5)**	(3.5)	(3.4)
Investment tax credit amortization	**1.2**	1.4	1.3
Progress Energy tax allocation benefit	**2.5**	2.7	3.8
Other differences, net	**0.6**	1.3	(0.3)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Income tax expense (benefit) applicable to continuing operations is comprised of (in millions):

Florida Progress	2004	2003	2002
Current - federal	$ 46	$ 6	$ 43
State	31	18	23
Deferred - federal	(16)	(123)	(220)
State	15	(5)	(13)
Investment tax credit	(6)	(6)	(6)
Total income tax expense (benefit)	$ 70	$ (110)	$ (173)

Progress Energy Florida	2004	2003	2002
Current - federal	$ 55	$ 145	$ 172
State	9	27	29
Deferred - federal	98	(16)	(29)
State	18	(3)	(3)
Investment tax credit	(6)	(6)	(6)
Total income tax expense (benefit)	$ 174	$ 147	$ 163

Florida Progress and each of its wholly-owned subsidiaries have entered into a Tax Agreement with Progress Energy (See Note 1D). The Company's intercompany tax payable was approximately $72 million and $17 million at December 31, 2004 and 2003, respectively. Progress Energy Florida's intercompany tax payable was approximately $21 million and $16 million at December 31, 2004 and 2003, respectively.

Florida Progress, through its subsidiaries, is a majority owner in two entities and a minority owner in four entities that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied (See Note 21E).

15. BENEFIT PLANS

The Company and some of its subsidiaries (including PEF) have a non-contributory defined benefit retirement (pension) plan for substantially all full-time employees. The Company also has supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, the Company and some of its subsidiaries (including PEF) provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. The Company uses a measurement date of December 31 for its pension and OPEB plans.

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

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2004	2003	2002	2004	2003	2002
Service cost	$ 22	$ 21	$ 19	$ 4	$ 5	$ 5
Interest cost	48	46	44	14	16	15
Expected return on plan assets	(77)	(62)	(76)	(1)	(1)	(1)
Net amortization	1	3	(7)	5	5	4
Net cost/(benefit) recognized by Florida Progress	$ (6)	$ 8	$ (20)	$ 22	$ 25	$ 23
Net cost/(benefit) recognized by PEF	$ (8)	$ 5	$ (22)	$ 21	$ 24	$ 22

The net periodic cost for other postretirement benefits decreased during 2004 due to the implementation of FASB Staff Position 106-2 (See Note 2).

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% of the greater of the obligation or the market-related value of assets are amortized over the average remaining service period of active participants. The Company uses fair value for the market-related value of assets.

Reconciliations of the changes in the plans' benefit obligations and the plans' funded status are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2004**	2003	**2004**	2003
Obligation at January 1	$ **780**	$ 714	$ **224**	$ 236
Service cost	**22**	21	**4**	5
Interest cost	**48**	46	**14**	15
Plan amendments	**2**	–	**–**	–
Benefit payments	**(42)**	(41)	**(17)**	(15)
Actuarial loss (gain)	**39**	40	**15**	(17)
Obligation at December 31	**849**	780	**240**	224
Fair value of plan assets at December 31	**919**	849	**20**	18
Funded status	**70**	69	**(220)**	(206)
Unrecognized transition obligation	**–**	–	**28**	31
Unrecognized prior service cost (benefit)	**(14)**	(18)	**6**	7
Unrecognized net actuarial loss	**117**	111	**30**	15
Minimum pension liability adjustment	**(14)**	(11)	**–**	–
Prepaid (accrued) cost at December 31, net – Florida Progress	$ **159**	$ 151	$ **(156)**	$ (153)
Prepaid (accrued) cost at December 31, net – PEF	$ **192**	$ 183	$ **(150)**	$ (148)

The 2003 OPEB obligation information above has been restated due to the implementation of FASB Staff Position 106-2 (See Note 2).

The Florida Progress net prepaid pension cost of $159 million and $151 million at December 31, 2004 and 2003, respectively, is included in the Company's Consolidated Balance Sheets as prepaid pension cost of $238 million and $223 million, respectively, which is included in other assets and deferred debits, and accrued benefit cost of $79 million and $72 million, respectively, which is included in accrued pension and other benefits. The PEF net prepaid pension cost of $192 million and $183 million at December 31, 2004 and 2003, respectively, is included in the Balance Sheets as prepaid pension cost of $234 million and $220 million, respectively, and accrued benefit cost of $42 million and $37 million, respectively, which is included in accrued pension and other benefits. For Florida Progress, the defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $80 million and $74 million at December 31, 2004 and 2003, respectively. Those plans had accumulated benefit obligations totaling $77 million and $73 million, respectively, and no plan assets. For PEF, the defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $41 million and $38 million at December 31, 2004 and 2003, respectively. Those plans had accumulated benefit obligations totaling $39 million and $37 million, respectively, and no plan assets. For Florida Progress, the total accumulated benefit obligation for pension plans was $797 million and $736 million at December 31, 2004 and 2003, respectively. For PEF, the total accumulated benefit obligation for pension plans was $718 million and $659 million at December 31, 2004 and 2003, respectively. Accrued other postretirement benefit cost is included in accrued pension and other benefits in the respective Balance Sheets of Florida Progress and PEF.

Florida Progress and PEF recorded a minimum pension liability adjustment of $14 million and $7 million, respectively, at December 31, 2004, with a corresponding charge of $7 million to a regulatory asset and, for Florida Progress, a pre-tax charge of $7 million to accumulate other comprehensive loss, a component of common stock equity. Florida Progress and PEF recorded a minimum pension liability adjustment of $11 million and $6 million, respectively, at December 31, 2003, with a corresponding pre-tax charge to accumulated other comprehensive loss, a component of common stock equity.

Reconciliations of the fair value of plan assets are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2004**	2003	**2004**	2003
Fair value of plan assets January 1	**$ 849**	$ 687	**$ 18**	$ 16
Actual return on plan assets	**108**	199	**1**	1
Benefit payments	**(42)**	(41)	**(18)**	(15)
Employer contributions	**4**	4	**19**	16
Fair value of plan assets at December 31	**$ 919**	$ 849	**$ 20**	$ 18

In the table above, substantially all employer contributions represent benefit payments made directly from Company assets. The remaining benefits payments were made directly from plan assets. The OPEB benefit payments represent the net Company cost after participant contributions. Participant contributions represent approximately 10% of gross benefit payments.

The asset allocation for the Company's plans at the end of 2004 and 2003 and the target allocation for the plans, by asset category, are as follows:

	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	2005	**2004**	2003	2005	**2004**	2003
Equity – domestic	48%	**47%**	49%	–	**–**	–
Equity – international	15%	**21%**	22%	–	**–**	–
Debt – domestic	12%	**9%**	11%	100%	**100%**	100%
Debt – international	10%	**11%**	11%	–	**–**	–
Other	15%	**12%**	7%	–	**–**	–
Total	100%	**100%**	100%	100%	**100%**	100%

With regard to its pension assets, the Company sets strategic 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, the Company employs external investment managers who have complementary investment philosophies and approaches. Tactical shifts (plus or minus five percent) in asset allocation from the strategic allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes. The Company's OPEB assets are invested solely in fixed income securities.

In 2005, the Company expects to make no required contributions to pension plan assets and $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately $43, $45, $47, $51, $55 and $337, respectively. The expected benefit payments for the OPEB plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately $17, $19, $20, $21, $22 and $126, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from Company assets. The benefit payment amounts reflect the net cost to the Company after any participant contributions. The Company expects to begin receiving prescription drug-related federal subsidies in 2006 (See Note 2), and the expected subsidies for 2006 through 2009 and in total for 2010-2014, in millions, are approximately $2, $2, $2, $2 and $14, respectively. PEF represents a significant majority of the Company's expected benefit payments and expected subsidies to be received. The expected benefit payments above do not include the potential effects of a 2005 voluntary early retirement program (see Note 22).

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

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
Discount rate	**5.90%**	6.30%	**5.90%**	6.30%
Rate of increase in future compensation				
Bargaining	**3.50%**	3.50%	–	–
Supplementary plans	**5.25%**	5.00%	–	–
Initial medical cost trend rate for pre-Medicare benefits	–	–	**7.25%**	7.25%
Initial medical cost trend rate for post-Medicare benefits	–	–	**7.25%**	7.25%
Ultimate medical cost trend rate	–	–	**5.00%**	5.25%
Year ultimate medical cost trend rate is achieved	–	–	**2008**	2009

The Company's primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in Emerging Issues Task Force Issue No. 03-4. Therefore, effective December 31, 2003, the Company 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.

The following weighted-average actuarial assumptions were used in the calculation of the net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**6.30%**	6.60%	7.50%	**6.30%**	6.60%	7.50%
Rate of increase in future compensation						
Bargaining	**3.50%**	3.50%	3.50%	–	–	
Nonbargaining	–	4.00%	4.00%	–	–	–
Supplementary plan	**5.00%**	4.00%	4.00%	–	–	
Expected long-term rate of return on plan assets	**9.25%**	9.25%	9.25%	**5.00%**	5.00%	5.00%

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 pension plan assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. The Company has chosen to use an expected long-term rate of 9.25%. The OPEB expected long-term rate of return of 5.0% reflects that the OPEB assets are invested solely in fixed income securities.

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. Assuming a 1% increase in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would increase by $1 million, and the OPEB obligation at December 31, 2004, would increase by $13 million. Assuming a 1% decrease in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2004 would decrease by $1 million and the OPEB obligation at December 31, 2004, would decrease by $12 million.

16. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

Under its risk management policy, the Company and PEF 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. The Company and PEF minimize such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties. Potential non-performance by counterparties is not expected to have a material effect on the consolidated financial position or consolidated results of operations of the Company or PEF.

A. Commodity Derivatives

GENERAL

Most of the Company's and PEF's commodity contracts either are not derivatives or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity forward contracts, may be entered into for economic hedging purposes. While management believes these derivatives mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. The Company manages open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material during 2004, 2003 or 2002, and the Company did not have material outstanding positions in such contracts at December 31, 2004 or 2003.

In 2004, PEF entered into derivative instruments related to its exposure to price fluctuations on fuel oil purchases. At December 31, 2004, the fair values of these 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. These instruments receive regulatory accounting treatment. Gains are recorded in regulatory liabilities and losses are recorded in regulatory assets.

CASH FLOW HEDGES

The Company's 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 for the Company's forecasted sales. In the normal course of business, Progress Fuels through an affiliate, Progress Ventures, Inc. (PVI), enters natural gas cash flow hedging instruments, which PVI offsets with third party transactions. Progress Fuels accounts for such contracts as if it were transacted with a third party and records the contract using mark-to-market or accrual accounting, as applicable. At December 31, 2004, Progress Fuels is hedging exposures to the price variability of natural gas through December 2005.

The total fair value of these instruments at December 31, 2004 and 2003 was a $9 million and a $14 million liability position, respectively. The ineffective portion of commodity cash flow hedges was not material in 2004 and 2003. At December 31, 2004, there were $5 million of after-tax deferred losses in accumulated other comprehensive income (OCI). The entire amount is expected to be reclassified to earnings during the next 12 months as the hedged transactions occur. As part of the divestiture of Winchester Production Company, Ltd. assets in 2004, $7 million of after-tax deferred losses were reclassified into earnings due to discontinuance of the related cash flow hedges (See Note 4A). Due to the volatility of the commodities markets, the value in OCI is subject to change prior to its reclassification into earnings.

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

The Company and PEF manage its interest rate exposure in part by maintaining its variable-rate and fixed rate-exposures within defined limits. In addition, the Company and PEF also enter into financial derivative instruments, including, but not limited to, interest rate swaps and lock agreements to manage and mitigate interest rate risk exposure.

The Company and PEF use cash flow hedging strategies to hedge variable interest rates on long-term debt and to hedge interest rates with regard to future fixed-rate debt issuances. The Company and PEF held no interest rate cash flow hedges at December 31, 2004 or 2003. At December 31, 2004, an immaterial amount of after-tax deferred losses in OCI, related to previously terminated hedges at PEF, is expected to be reclassified to earnings during the next 12 months as the hedged interest payments occur.

The Company and PEF use fair value hedging strategies to manage its exposure to fixed interest rates on long-term debt. At December 31, 2004 and 2003, the Company and PEF had no open interest rate fair value hedges.

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 these transactions is the cost of replacing the agreements at current market rates.

17. RELATED PARTY TRANSACTIONS

The Parent's subsidiaries provide and receive services, at cost, to and from the Company and its subsidiaries, in accordance with agreements approved by the U.S. Securities and Exchange Commission (SEC) pursuant to Section 13(b) of the PUHCA. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, constructions 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 which 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 Consolidated Balance Sheets.

Progress Energy Service Company, LLC (PESC) provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2004, 2003 and 2002 to Florida Progress amounted to $199 million, $190 million and $173 million, respectively, and services provided to PEF were $165 million, $153 million and $161 million, respectively. Based on a standard review by the Office of Public Utility Regulation within the SEC the method for allocating certain PESC governance costs changed and retroactive reallocations for 2002 and 2001 charges were recorded in 2003. The net after-tax impact of the reallocation on 2003 was an increase in expenses of $5 million at Florida Progress and a reduction of expenses at PEF by $1 million. PEF and an affiliated utility also provide and receive services at cost. Services received by PEF during 2004, 2003 and 2002 amounted to $52 million, $35 million and $72 million, respectively. Services provided by PEF during 2004, 2003 and 2002 amounted to $16 million, $7 million and $16 million, respectively.

Progress Fuels sells coal to PEF for insignificant profits. These intercompany revenues and expenses are eliminated in consolidations; 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 $331 million, $346 million and $329 million for the years ended December 31, 2004, 2003 and 2002, respectively, are included in fuel used in electric generation on Florida Progress' Consolidated and PEF's Statements of Income.

The Company and its subsidiaries participate in money pools, operated by Progress Energy, to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pools are also used to settle intercompany balances. The weighted-average interest rate for the money pools was 1.72%, 1.47% and 2.18% at December 31, 2004, 2003 and 2002, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. Net interest expense related to money pool borrowings was $7 million for 2004 and $5 million for Florida Progress for 2003 and 2002. PEF recorded insignificant interest expense related to the money pool for the three years presented.

As a part of normal business, Progress Energy and certain subsidiaries 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. As of December 31, 2004 Progress Energy and certain subsidiaries issued guarantees of $140 million supporting obligations under coal brokering operations and other agreements of subsidiaries. Progress Energy and certain subsidiaries also purchased $33 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $40 million. Florida Progress has fully guaranteed the medium term notes outstanding for Progress Capital, a wholly owned subsidiary of Florida Progress. At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheets.

In April 2000, Progress Ventures, Inc. (PVI), a wholly owned subsidiary of Progress Energy, purchased a 90% interest in an affiliate of Progress Fuels that owns a synthetic fuel facility located at the Company-owned mine site in Virginia. In May 2000, PVI purchased a 90% ownership interest in another synthetic fuel facility located

in West Virginia. The purchase agreements contained a provision that would require PVI to sell, and the respective Progress Fuels affiliate to repurchase, the 90% interest had the share exchange among Florida Progress, Progress Energy and CP&L not occurred. Progress Fuels has accounted for the transactions as a sale for tax purposes and, because of the repurchase obligation, as a financing for financial reporting purposes in the pre-acquisition period and as a transfer of assets within a controlled group as of the acquisition date. At the date of acquisition, assets of $8 million were transferred to Progress Energy. At December 31, 2004 and 2003, the Company has a note receivable of $28 million and $37 million from PVI that has been recorded as a reduction to equity for financial reporting purposes. Payments included insignificant amounts of interest for the three years presented.

PVI enters into derivative transactions on behalf of Progress Fuels, which are discussed further with the derivatives transactions (See Note 16A). PVI recorded $33 million, $28 million and $9 million of realized and unrealized gains for these derivative transactions in 2004, 2003 and 2002, respectively.

Progress Fuels sells coal feedstock to PVI to be used in its two synthetic fuel operations and is also the sales agent and operator of the facilities. The amount of revenue for sales and services during 2004, 2003 and 2002 was $134 million, $182 million and $197 million, respectively.

During 2003, in order to more effectively utilize cash resources, Progress Fuels and the two PVI synthetic fuel operations began to participate in a money pool with cash management functions provided by Progress Fuels. Amounts payable to the money pool of $61 million and $34 million are included in notes payable to affiliated companies on the Consolidated Balance Sheets. Interest related to the money pool was insignificant for the three years presented.

A Progress Fuels subsidiary sells coal feedstock to an equity investment. The amount of revenue during 2004, 2003 and 2002 was $150 million, $117 million and $101 million, respectively.

Long-term debt, affiliate on the Florida Progress' Consolidated Balance Sheet consists of $500 million for Progress Fuels' unsecured note with Parent and $309 million of debt to an affiliated trust (See Note 12A). Progress Fuels recorded interest expense related to the unsecured note with Parent of $32 million for 2004 and 2003. The annual interest expense to the affiliated trust is $21 million and is reflected in the Consolidated Statements of Income.

Florida Progress Funding Corporation (Funding Corp.) $309 million 7.10% Junior Subordinated Deferrable Interest Notes (Subordinated Notes) are due to FPC Capital I (the Trust) (See Note 12A). The Trust was established for the sole purpose of issuing $300 million Preferred Securities and using the proceeds thereof to purchase from Funding Corp. its Subordinated Notes. The Company has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, the Company has 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 (Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by the Company of the Trust's obligations under the Preferred Securities. The Subordinated Notes and the Notes Guarantee are the sole assets of the Trust. The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest. 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 Company and each of its wholly owned subsidiaries have entered into a Tax Agreement with Progress Energy (See Note 14).

18. FINANCIAL INFORMATION BY BUSINESS SEGMENT

The Company's principal business segment is PEF, a utility engaged in the generation, purchase, transmission, distribution and sale of electricity primarily in Florida. The other reportable business segments are Progress Fuels' Energy & Related Services and Rail Services. The Energy & Related Services segment includes coal and synthetic fuel operations, natural gas production and sales, river terminal services and off-shore marine transportation. Rail Services' operations include railcar repair, rail parts reconditioning and sales, railcar leasing and sales, providing rail and track material, and scrap metal recycling. The Other category consists primarily of PTC, the Company's telecommunications subsidiary and the holding company, Florida Progress Corporation and eliminations. PTC markets wholesale fiber-optic based capacity service in the Eastern United States and also

markets wireless structure attachments to wireless communication companies and governmental entities. The Company allocates a portion of its operating expenses to business segments.

The Company's significant operations are geographically located in the United States with limited operations in Mexico and Canada. The Company's segments are based on differences in products and services, and therefore no additional disclosures are presented. Intersegment sales and transfers consist primarily of coal sales from the Energy and Related Services segment of Progress Fuels to PEF. The price Progress Fuels charges PEF is based on market rates for coal procurement and for water-borne transportation under a methodology approved by the FPSC. Rail transportation is also based on market rates plus a return allowed by the FPSC on equity in transportation equipment utilized in transporting coal to PEF. The allowed rate of return is currently 12%. No single customer accounted for 10% or more of unaffiliated revenues.

Segment net income (loss) for 2004 includes a gain on the sale of certain gas properties and assets of $56 million ($31 million after-tax) and a long-lived asset impairment on goodwill at Diamond May of $8 million before and after tax included in the Energy and Related Services segment. Segment net income (loss) for 2003 includes a long-lived asset impairment on certain assets at Kentucky May Mining Company of $15 million ($10 million after-tax) included in the Energy and Related Services segment. Segment net income (loss) for 2002 includes an estimated impairment on the assets held for sale of Railcar Ltd., of $67 million pre-tax ($45 million after-tax) included in the Rail Services segment and an asset impairment and other charges related to PTC totaling $233 million on a pre-tax basis ($144 million after-tax) included in the Other segment. The Company's business segment information for 2004, 2003 and 2002 is summarized below.

(in millions)	Utility	Energy and Related Services	Rail Services	Other	Consolidated
Year Ended December 31, 2004					
Unaffiliated revenues	$ 3,525	$ 1,223	$ 1,130	$ 57	$ 5,935
Intersegment revenues	–	331	1	(332)	–
Total revenues	3,525	1,554	1,131	(275)	5,935
Depreciation and amortization	281	80	21	11	393
Total interest charges, net	114	20	27	19	180
Gain on sale of assets	–	54	–	–	54
Impairment of goodwill and long-lived assets	–	8	–	–	8
Income tax expense (benefit)	174	(106)	15	(13)	70
Income (loss) from continuing operations	333	137	16	(12)	474
Total segment assets	7,924	855	596	311	9,686
Capital and investment expenditures	482	157	40	6	685
Year Ended December 31, 2003					
Unaffiliated revenues	$ 3,152	$ 982	$ 846	$ 28	$ 5,008
Intersegment revenues	–	346	1	(347)	–
Total revenues	3,152	1,328	847	(319)	5,008
Depreciation and amortization	307	66	20	6	399
Total interest charges, net	91	22	29	21	163
Impairment of goodwill and long-lived assets	–	15	–	–	15
Income tax expense (benefit)	147	(246)	2	(13)	(110)
Income (loss) from continuing operations	295	166	(1)	(17)	443
Total segment assets	7,280	977	586	350	9,193
Capital and investment expenditures	526	310	103	11	950

Year Ended December 31, 2002					
Unaffiliated revenues	$ 3,062	$ 690	$ 714	$ 34	$ 4,500
Intersegment revenues	–	329	5	(334)	
Total revenues	3,062	1,019	719	(300)	4,500
Depreciation and amortization	295	34	20	12	361
Total interest charges, net	106	22	33	22	183
Impairment of goodwill and long-lived assets	–	–	67	214	281
Income tax expense (benefit)	163	(207)	(19)	(110)	(173)
Income (loss) from continuing operations	323	122	(47)	(168)	230
Total segment assets	6,678	794	529	137	8,138
Capital and investment expenditures	535	121	8	42	706

Geographic Data

	U.S.	Canada	Mexico	Consolidated
2004				
Consolidated revenues	**$ 5,807**	**$ 112**	**$ 16**	**$ 5,935**
2003				
Consolidated revenues	$ 4,891	$ 103	$ 14	$ 5,008
2002				
Consolidated revenues	$ 4,393	$ 93	$ 14	$ 4,500

19. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income and other income and expense items as discussed below. The components of other, net as shown on the Statements of Income for fiscal years 2004, 2003 and 2002 are as follows:

(in millions)	2004	2003	2002
Other income			
Nonregulated energy and delivery services income	17	14	17
AFUDC equity	7	12	2
Other	3	1	4
Total other income – Progress Energy Florida	$ 27	$ 27	$ 23
Other income – Florida Progress	13	5	6
Total other income – Florida Progress	$ 40	$ 32	$ 29
Other expense			
Nonregulated energy and delivery services expenses	$ 11	$ 11	$ 15
Donations	8	9	10
Other	3	–	5
Total other expense – Progress Energy Florida	$ 22	$ 20	$ 30
Loss from equity investments	12	15	14
Other expense – Florida Progress	5	5	5
Total other expense – Florida Progress	$ 39	$ 40	$ 49
Other, net	$ 1	$ (8)	$ (20)

Nonregulated energy and delivery services include power protection services and mass market programs (surge protection, appliance services and area light sales) and delivery, transmission and substation work for other utilities.

20. ENVIRONMENTAL MATTERS

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

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. The Company and PEF are periodically notified by regulators such as the EPA and various state agencies of its involvement or potential involvement in sites, other than MGP sites, that may require investigation and/or remediation. The Company and PEF are also currently in the process of assessing potential costs and exposures at other environmentally impaired sites. For all sites the assessments are developed and analyzed, the Company and PEF will accrue costs for the sites to the extent the costs are probable and can be reasonably estimated.

Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. The principal regulatory agency that is responsible for a specific former manufactured gas plant (MGP) site depends largely upon the state in which the site is located. There are several MGP sites to which the Company, through PEF, has some connection. In this regard, PEF and other potentially responsible parties (PRPs), are participating in, investigating and, if necessary, remediating former MGP sites with several regulatory agencies, including, but not limited to, the U.S. Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP).

The Florida Legislature passed risk-based corrective action (RBCA, known as Global RBCA) legislation in the 2003 regular session. 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 law 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. The FDEP has developed the rules required by the RBCA statute, holding meetings with interested stakeholders and hosting public workshops. The rules have the potential for making future cleanups in Florida more costly to complete. The Global RBCA rule was adopted at the February 2, 2005 Environmental Review Commission hearing. The effective date of the Global RBCA rule is expected to be announced in April 2005. The Company and PEF are in the process of assessing the impact of this matter.

The Company and PEF have filed claims with the Company's general liability insurance carriers to recover costs arising out of actual or potential environmental liabilities. Some claims have been settled and others are still pending. The Company and PEF cannot predict the outcome of this matter.

PEF

At December 31, 2004 and 2003, PEF'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 many years, were:

(in millions)	2004	2003
Remediation of distribution and substation transformers	$ 27	$ 12
MGP and other sites	18	6
Total accrual for environmental sites	$ 45	$ 18

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 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. Through 2004 PEF has reviewed a number of distribution transformer sites and substation sites. PEF expects to have completed its review of distribution transformer sites by the end of 2007 and has completed the review of substation sites in 2004. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC clause. In 2004, PEF accrued an additional $19 million, due to identification of additional sites requiring remediation, and spent approximately $4 million 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 costs. In 2004, PEF received approximately $12 million in insurance claim settlement proceeds and recorded a related accrual for associated environmental expenses. The proceeds are restricted for use in addressing costs associated with environmental liabilities. Expenditures for the year were less than $1 million.

These accruals have been recorded on an undiscounted basis. PEF measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. This process often includes assessing and developing cost-sharing arrangements with other PRPs. 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 advanced to the stage where a reasonable estimate of the remediation costs can be made, at this time PEF is unable to provide an estimate of its obligation to remediate these sites beyond what is currently accrued. As more activity occurs at these sites, PEF will assess the need to adjust the accruals. It is anticipated that sufficient information will become available in 2005 to make a reasonable estimate of PEF's obligation for one of the MGP sites.

FLORIDA PROGRESS CORPORATION

In 2001, FPC established a $10 million accrual to address indemnities and retained an environmental liability associated with the sale of its Inland Marine Transportation business. In 2003, the accrual was reduced to $4 million based on a change in estimate. During 2004, expenditures related to this liability were not material to the Company's financial condition. As of December 31, 2004, the remaining accrual balance was approximately $3 million and is included in other liabilities and deferred credits. FPC measures its liability for this site based on estimable and probable remediation scenarios.

Certain historical sites are being addressed voluntarily by FPC. An immaterial accrual has been established to address investigation expenses related to these sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

RAIL

Rail Services is voluntarily addressing certain historical waste sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

AIR QUALITY

Congress is considering legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs which could be material to the Company and PEF's consolidated financial position or results of operations. However, the Company and PEF cannot predict the outcome of this matter.

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 New Source Review requirements or New Source Performance Standards under the Clean Air Act. The Company was 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 other 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 cost through rate adjustments or similar mechanisms. The Company and PEF cannot predict the outcome of this matter.

In 2003, the EPA published a final rule addressing routine equipment replacement under the New Source Review program. The rule defines routine equipment replacement and the types of activities that are not subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The rule was challenged in the Federal Appeals Court and its implementation stayed. In July 2004, the EPA announced it will reconsider certain issues arising from the final routine equipment replacement rule. The comment period closed on August 30, 2004. The Company and PEF cannot predict the outcome of this matter.

In 1997, the EPA's Mercury Study Report and Utility Report to Congress concluded that mercury is not a risk to the average person in America and expressed uncertainty about whether reductions in mercury emissions from coal-fired power plants would reduce human exposure. Nevertheless, the EPA determined in 2000 that regulation

of mercury emissions from coal-fired power plants was appropriate. In 2003, the EPA proposed alternative control plans that would limit mercury emissions from coal-fired power plants. The final rule was released on March 15, 2005. The EPA's rule establishes a mercury cap and trade program for coal-fired power plants that requires limits to be met in two phases, in 2010 and 2018. The Company and PEF are reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the mercury rule's requirements. Compliance plans and the cost to comply with the rule will be determined once the Company and PEF complete their review.

In conjunction with the proposed mercury rule, the EPA proposed a MACT standard to regulate nickel emissions from residual oil-fired units. The agency estimates the proposal will reduce national nickel emissions to approximately 103 tons. As proposed, the rule may require the company to install additional pollution controls on its residual oil-fired units, resulting in significant capital expenditures. PEF has eight units that are affected, and they currently do not have pollution controls in place that would meet the proposed requirements of the nickel rule. The EPA expects to finalize the nickel rule in March 2005. Compliance costs will be determined following promulgation of the rule.

In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The final rule was released on March 10, 2005. The EPA's rule requires 28 states and the District of Columbia, including Florida, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. The Company and PEF are reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the CAIR requirements. Compliance plans and the cost to comply with the rule, will be determined once the Company and PEF complete the review of the final rule.

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 PEF in the immediate and extended future.

After many years of litigation and settlement negotiations the EPA adopted regulations in February 2004 to implement Section 316(b) of the Clean Water Act. These regulations became effective September 7, 2004. The purpose of these regulations is to minimize adverse environmental impacts caused by cooling water intake structures and intake systems. Over the next several years these regulations will impact the larger base load generation facilities and may require the facilities to mitigate the effects to aquatic organisms by constructing intake modifications or undertaking other restorative activities. PEF currently estimates that from 2005 through 2009 the range of its expenditures to meet the Section 316(b) requirements of the Clean Water Act will be $65 million to $85 million.

OTHER ENVIRONMENTAL MATTERS

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of carbon dioxide and other greenhouse gases. In 2004, Russia ratified the Protocol, and 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. A number of carbon dioxide emissions control proposals have been advanced in Congress. Reductions in carbon dioxide emissions to the levels specified by the Kyoto Protocol and some legislative proposals could be materially adverse to the Company's consolidated financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. The Company favors the voluntary program approach recommended by the administration and continually evaluates options for the reduction, avoidance and sequestration of greenhouse gases. However, the Company and PEF cannot predict the outcome of this matter.

Progress Energy has announced its plan to issue a report on the Progress Energy's activities associated with current and future environmental requirements. The report will include a discussion of the environmental requirements that the Company and PEF currently face and expect to face in the future, as well as an assessment of potential mandatory constraints on carbon dioxide emissions. The report will be issued by March 31, 2006.

21. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2004, the following table reflects the Company's contractual cash obligations and other commercial commitments in the respective periods in which they are due.

(in millions)	2005	2006	2007	2008	2009	Thereafter
Fuel	$ 1,571	$ 1,023	$ 270	$ 102	$ 116	$ 684
Purchased power	334	342	354	364	331	4,086
Construction obligations	51	–	–	–	–	–
Other purchase obligations	44	38	36	22	20	93
Total	$ 2,000	$ 1,403	$ 660	$ 488	$ 467	$ 4,863

FUEL AND PURCHASED POWER

The Company has entered into various long-term contracts for oil, gas and coal. The Company's payments under these commitments were $1,620 million, $1,157 million and $891 million in 2004, 2003 and 2002, respectively. PEF's payments totaled $372 million, $208 million and $94 million in 2004, 2003 and 2002, respectively. The Company's estimated annual payments for firm commitments of fuel purchases and transportation costs under these contracts make up the fuel line in the previous table. PEF's future payments under these contracts at December 31, 2004 are $375 million, $258 million, $125 million, $102 million and $116 million for 2005 through 2009, respectively, and $684 million thereafter.

Progress Fuels had two coal supply contracts with PEF through 2005, which require PEF to buy and Progress Fuels to supply substantially all of the coal and transportation requirements of four of PEF's generating units. These contracts are renewable annually. Either party may terminate the contract with six months notice. In connection with these contracts, Progress Fuels has entered into several contracts with outside parties for the purchase of coal. The annual obligations for coal purchases and transportation under these contracts are $358 million and $286 million for 2005 and 2006, respectively, with no obligations thereafter. The total cost incurred for these commitments in 2004, 2003 and 2002 was $301 million, $284 million and $289 million, respectively.

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 $129 million, $124 million and $109 million for 2004, 2003 and 2002, respectively. Total capacity payments were $56 million, $55 million and $50 million for 2004, 2003 and 2002, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, at December 31, 2004 are $60 million, $63 million, $65 million, $66 million and $67 million for 2005 through 2009, respectively, and $244 million thereafter.

PEF has ongoing purchased power contracts with certain cogenerators (qualifying facilities) for 821 MW of capacity with expiration dates ranging from 2005 to 2025. These purchased power contracts provide for capacity and energy payments. 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% 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 $248 million, $244 million and $235 million for 2004, 2003 and 2002, respectively. Minimum expected future capacity payments under these contracts at December 31, 2004 are $271 million, $279 million, $289 million, $298 million and $263 million for 2005 through 2009, respectively, and $3.8 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 $3.3 billion. The transactions are subject to several conditions precedent, which include obtaining the Florida Public Service Commission'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 above.

CONSTRUCTION OBLIGATIONS

PEF has purchase obligations related to various plant capital projects at the Hines Complex. Total payments under these contracts were $97 million, $137 million and $130 million for 2004, 2003, and 2002, respectively. Future obligations under these contracts are $51 million for 2005.

OTHER PURCHASE OBLIGATIONS

PEF has long-term service agreements for the Hines Complex. Total payments under these contracts were $11 million, $3 million and $1 million for 2004, 2003 and 2002, respectively. Future obligations under these contracts are $6 million, $18 million, $11 million, $16 million and $14 million for 2005 through 2009, respectively, with approximately $93 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. At December 31, 2004, no purchases have been made under these contracts. Future obligations under these contracts are $34 million, $20 million and $25 million in 2005, 2006 and 2007, respectively, and $6 million in 2008 and 2009.

The Company incurred expenses related to various other purchase obligations allocated from PESC of $6 million for 2004 and 2003 and $5 million for 2002.

B. Other Commitments

The Company has certain future commitments related to synthetic fuel facilities purchased that provide for contingent payments (royalties). The related agreements and amendments require the payment of minimum annual royalties of which the Company's share is approximately $13 million through 2007. As a result of the amendment, Company 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 $37 million and $47 million at December 31, 2004 and 2003, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2004 and 2003, the portions of the asset and liability recorded that were classified as current were approximately $13 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. Actual amounts paid under these agreements were none in 2004, $1 million in 2003 and $24 million in 2002. Future expected royalty payments are approximately $13 million for 2005 through 2007. The Company has the right in the related agreements and their amendments that allow the Company to escrow those payments if certain conditions in the agreements are met. The Company has exercised that right and retained 2004 and 2003 royalty payments of approximately $20 million and $22 million, respectively, pending the establishment of the necessary escrow accounts. Once established, these funds will be placed into escrow.

C. Leases

The Company leases transportation equipment, office buildings, computer equipment, and other property and equipment with various terms and expiration dates. The Company generally requires the subsidiaries to pay all executory costs such as maintenance and insurance. Some rental payments include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Rent expense under operating leases totaled $45 million, $40 million and $49 million during 2004, 2003 and 2002, respectively. These amounts include rent expense allocated from PESC to the Company of $12 million for 2004, 2003 and 2002. PEF's rent expense totaled $14 million, $17 million and $16 million during 2004, 2003 and 2002, respectively. These amounts include rent expense allocated from PESC to PEF of $10 million for 2004, 2003 and 2002.

In addition, PTC has entered into capital leases for equipment. Assets recorded under capital leases totaled $2 million and $4 million at December 31, 2004 and 2003, respectively. Accumulated amortization was not significant. These assets were written down in conjunction with the impairments of PTC recorded during the third quarter of 2002 (See Note 10). PEF does not have any capital leases.

Minimum annual rental payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable leases at December 31, 2004 are:

		Operating Leases	
(in millions)	Capital Leases	Florida Progress	Progress Energy Florida
2005	$ 2	$ 22	$ 11
2006	2	19	9
2007	1	36	28
2008	1	37	30
2009	1	36	29
Thereafter	8	170	132
	$ 15	$ 320	$ 239
Less amount representing imputed interest	(5)		
Present value of net minimum lease payments under capital lease	$ 10		

FPC, excluding PEF, is also a lessor of land, buildings, railcars and other types of properties it owns under operating leases with various terms and expiration dates. The leased buildings and railcars are depreciated under the same terms as other buildings and railcars included in diversified business property. Minimum rentals receivable under noncancelable leases for 2005 through 2009, in millions is $31, $22, $13, $8 and $6, respectively and $16 million thereafter. Rents received under operating leases totaled $63 million, $46 million and $53 million for 2004, 2003 and 2002, respectively.

PEF is the lessor of electric poles, streetlights and other facilities. Rents received are based on a fixed minimum rental where price varies by type of equipment and totaled $63 million, $56 million and $52 million for 2004, 2003 and 2002, respectively. Minimum rentals receivable (excluding streetlights) under noncancelable leases for 2005 through 2009, in millions is $5, $1, $1, $1 and $1, respectively, and $8 million thereafter. Streetlight rentals were $40 million, $38 million and $34 million for 2004, 2003 and 2002 respectively. Future streetlight rentals would approximate 2004 revenues.

D. Guarantees

To facilitate commercial transactions of the Company's subsidiaries Progress Energy and certain wholly owned subsidiaries enter into agreements providing future financial or performance assurances to third parties (See Note 17). At December 31, 2004, Progress Fuels had issued guarantees on behalf of third parties with an estimated maximum exposure of approximately $10 million. These guarantees support synthetic fuel operations. At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements.

In connection with the sale of partnership interests in Colona (See Note 4B), Progress Fuels indemnified the buyers against any claims related to Colona resulting from violations of any environmental laws. Although the terms of the agreement provide for no limitation to the maximum potential future payments under the indemnification, the Company has estimated that the maximum total of such payments would not be material.

E. Claims and Uncertainties

OTHER CONTINGENCIES

1. Franchise Litigation

Three cities, with a total of approximately 18,000 customers, have litigation pending against PEF in various circuit courts in Florida. As previously reported, three other cities, with a total of approximately 30,000 customers, have subsequently settled their lawsuits with PEF and signed new, 30-year franchise agreements. The lawsuits principally seek (1) a declaratory judgment that the cities have the right to purchase PEF's electric distribution system located within the municipal boundaries of the cities, (2) a declaratory judgment that the value of the distribution system must be determined through arbitration, and (3) injunctive relief requiring PEF to continue to collect from PEF's customers and remit to the cities, franchise fees during the pending litigation, and as long as PEF continues to occupy the cities' rights-of-way to provide electric service, notwithstanding the expiration of the franchise ordinances under which PEF had agreed to collect such fees. The circuit courts in those cases have entered orders requiring arbitration to establish the purchase price of PEF's electric distribution

system within five cities. Two appellate courts have upheld those circuit court decisions and authorized the cities to determine the value of PEF's electric distribution system within the cities through arbitration.

Arbitration in one of the cases (with the 13,000-customer City of Winter Park) was completed in February 2003. That arbitration panel issued an award in May 2003 setting the value of PEF's distribution system within the City of Winter Park (the City) at approximately $32 million, not including separation and reintegration and construction work in progress, which could add several million dollars to the award. The panel also awarded PEF approximately $11 million in stranded costs, which, according to the award, decrease over time. In September 2003, Winter Park voters passed a referendum that would authorize the City to issue bonds of up to approximately $50 million to acquire PEF's electric distribution system. While the City has not yet definitively decided whether it will acquire the system, on April 26, 2004, the City Commission voted to proceed with the acquisition. The City sought and received wholesale power supply bids and on June 24, 2004, executed a wholesale power supply contract with PEF. On May 12, 2004, the City solicited bids to operate and maintain the distribution system and awarded a contract in January 2005. The City has indicated that its goal is to begin electric operations in June 2005. On February 10, 2005, PEF filed a petition with the Florida Public Service Commission to relieve the Company of its statutory obligation to serve customers in Winter Park on June 1, 2005, or at such time when the City is able to provide retail service. At this time, whether and when there will be further proceedings regarding the City of Winter Park cannot be determined.

Arbitration with the 2,500-customer Town of Belleair was completed in June 2003. In September 2003, the arbitration panel issued an award in that case setting the value of the electric distribution system within the Town at approximately $6 million. The panel further required the Town to pay to PEF its requested $1 million in separation and reintegration costs and $2 million in stranded costs. The Town has not yet decided whether it will attempt to acquire the system; however, on January 18, 2005, it issued a request for proposals for wholesale power supply and to operate and maintain the distribution system. Proposals are due in early March 2005. In February 2005, the Town Commission also voted to put the issue of whether to acquire the distribution system to a voter referendum on or before October 2, 2005. At this time, whether and when there will be further proceedings regarding the Town of Belleair cannot be determined.

Arbitration in the remaining city's litigation (the 1,500-customer City of Edgewood) has not yet been scheduled. On February 17, 2005, the parties filed a joint motion to stay the litigation for a 90-day period during which the parties will discuss potential settlement.

A fourth city (the 7,000-customer City of Maitland) is contemplating municipalization and has indicated its intent to proceed with arbitration to determine the value of PEF's electric distribution system within the City. Maitland's franchise expires in August 2005. At this time, whether and when there will be further proceedings regarding the City of Maitland cannot be determined.

As part of the above litigation, two appellate courts reached opposite conclusions regarding whether PEF must continue to collect from its customers and remit to the cities "franchise fees" under the expired franchise ordinances. PEF filed an appeal with the Florida Supreme Court to resolve the conflict between the two appellate courts. On October 28, 2004, the Court issued a decision holding that PEF must collect from its customers and remit to the cities franchise fees during the interim period when the city exercises its purchase option or executes a new franchise agreement. The Court's decision should not have a material impact on the Company.

2. DOE Litigation

Pursuant to the Nuclear Waste Policy Act of 1982, the predecessors to PEF entered into contracts with the U.S. Department of Energy (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.

DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, PEF filed a complaint with the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel (SNF) by failing to accept SNF from PEF facilities on or before January 31, 1998. Damages due to DOE's breach will likely exceed $100 million. Approximately 60 cases involving the Government's actions in connection with SNF are currently pending in the Court of Federal Claims.

DOE and the PEF parties 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 SNF and high level waste (HLW) by which the Government was contractually obligated to accept contract holders' SNF and/or HLW, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues are expected to be presented in the trials that are scheduled to occur by April 2005. Resolution of these issues in other cases could facilitate agreements by the parties in the PEF lawsuit, or at a minimum, inform the Court of decisions reached by other courts if they remain contested and require resolution in this case. The trial court has continued this stay until June 24, 2005.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at PEF's nuclear unit, Crystal River Unit No. 3 (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.

In July 2002, Congress passed an override resolution to Nevada's veto of DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nevada. In January 2003, the State of Nevada, Clark County, Nevada and the City of 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 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. EPA is currently reworking the standard but has not stated when the work will be complete. 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, DOE announced it would not submit the license application until mid-2005 or later. Also in November 2004, Congressional negotiators approved $577 million for fiscal year 2005 for the Yucca Mountain project, approximately $300 million less than requested by DOE but approximately the same as approved in 2004. The DOE continues to state it plans to begin operation of the repository at Yucca Mountain in 2010. PEF cannot predict the outcome of this matter.

3. Advanced Separation Technologies (AST)

In 1996, Florida Progress sold its 80% interest in AST to Calgon Carbon Corporation (Calgon) for net proceeds of $56 million in cash. In 1998, Calgon filed a lawsuit against Florida Progress and the other selling shareholder and amended it in April 1998, alleging misstatement of AST's 1996 revenues, assets and liabilities, seeking damages and granting Calgon the right to rescind the sale. The lawsuit also accused the sellers of failing to disclose flaws in AST's manufacturing process and a lack of quality control.

All parties filed motions for summary judgment in July 2001. The summary judgment motions of Calgon and the other selling shareholder were denied in April 2002. The summary judgment motion of Florida Progress was withdrawn pending a legal challenge to portions of the report of Calgon's expert, Arthur Andersen, which had been used to oppose summary judgment. In September 2003, the United States District Court for the Western District of Pennsylvania issued final orders excluding from evidence in the case that portion of Arthur Andersen's damage analysis based on the discounted cash flow methodology of valuation. The Court did not exclude Arthur Andersen's use of the guideline publicly traded company methodology in its damage analysis. Florida Progress filed a renewed motion for summary judgment in October 2003, which is pending. Because the motion has now been outstanding for over a year, a ruling on the motion is expected at any time.

Florida Progress believes that the aggregate total of all legitimate warranty claims by customers of AST for which it is probable that Florida Progress will be responsible for under the Stock Purchase Agreement with Calgon is approximately $3 million, and accordingly, accrued $3 million in the third quarter of 1999 as an estimate of probable loss.

The Company cannot predict the outcome of this matter, but will vigorously defend against the allegations.

4. Synthetic Fuel Tax Credits

At December 31, 2003, Florida Progress, through its subsidiaries, was a majority-owner in three entities and a minority owner in three entities that own facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). In June 2004, Progress Fuels sold, in two transactions, a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its majority owned synthetic fuel operations. The Company is now a minority owner in Colona, but continues to consolidate Colona in accordance with FASB Interpretation No. 46R. Florida Progress, through its subsidiaries, is currently a majority owner in two synthetic fuel entities and a minority owner in four synthetic fuel entities, including Colona. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 of the Code (Section 29) 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 amount of Section 29 credits that the Company is allowed to claim in any calendar year is limited by the amount of the Company's regular federal income tax liability. Synthetic fuel tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. All majority-owned and minority-owned entities received private letter rulings (PLRs) from the Internal Revenue Service (IRS) with respect to their synthetic fuel operations. However, these PLR's do not address the placed–in-service date determinations. The PLRs do not limit the production on which synthetic fuel credits may be claimed. Total Section 29 credits generated to date are approximately $918 million, of which $432 million has been used to offset regular federal income tax liability and $481 million are being carried forward as deferred alternative minimum tax credits. Also $5 million has not been recognized due to the decrease in tax liability from the 2004 hurricane damage. The current Section 29 tax credit program expires at the end of 2007.

IMPACT OF HURRICANES

For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 4.9 million tons of synthetic fuel and the Company recorded $127 million of Section 29 tax credits. The amount of synthetic fuel sold and tax credits recorded in 2004 was impacted by hurricane costs which reduced the Company's projected 2004 regular tax liability.

For the nine months ended September 30, 2004, the Company's synthetic fuel facilities sold 4.6 million tons of synthetic fuel, which generated an estimated $119 million of Section 29 tax credits. Due to the anticipated decrease in the Company's tax liability as a result of expenses incurred for the 2004 hurricane damage, the Company estimated that it would be able to use in 2004, or carry forward to future years, only $72 million of these Section 29 tax credits. As a result, the Company recorded a charge of $47 million related to Section 29 tax credits at September 30, 2004.

On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from customers over a two-year period. Based on a reasonable expectation at December 31, 2004, that the FPSC will grant the requested recovery of the storm costs, the Company's loss from the casualty is less than originally anticipated. As of December 31, 2004, the Company estimates that it will be able to use in 2004, or carry forward to future years, $127 million of these Section 29 tax credits. Therefore, the Company recorded tax credits of $55 million for the quarter ended December 31, 2004, which the Company now anticipates can be used. For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 4.9 million tons of synthetic fuel, which generated an estimated $132 million of Section 29 tax credits. As of December 31, 2004, the Company anticipates that approximately $5 million of tax credits related to synthetic fuel sold during the year could not be used and have not been recognized.

The Company believes its right to recover storm costs is well established, however, the Company cannot predict the outcome of this matter. If the FPSC should deny PEF's petition for the recovery of storm costs in 2005, there could be a material impact on the amount of 2005 synthetic fuels production and results of operations.

IRS PROCEEDINGS

In September 2002, all of Florida Progress' majority-owned synthetic fuel entities at that time, including Colona, and two of the Company's minority owned synthetic fuel entities were accepted into the IRS's Pre-Filing Agreement (PFA) program. The PFA program allows taxpayers to voluntarily accelerate the IRS exam process in order to seek resolution of specific issues.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the IRS concerning their Colona synthetic fuel facilities. The Closing Agreement provided that the Colona facilities were placed in service before July 1, 1998, which is one of the qualification requirements for tax credits under Section 29 of the Code. The Closing Agreement further provides that the fuel produced by the Colona facilities in 2001 is a "qualified fuel" for purposes of the Section 29 tax credits. This action concluded the PFA program with respect to Colona.

In July 2004, Progress Energy was notified that the IRS field auditors anticipate taking an adverse position regarding the placed-in-service date of the Company's four Earthco synthetic fuel facilities. Due to the auditors' position, the IRS has decided to exercise its right to withdraw from the PFA program with Progress Energy. With the IRS's withdrawal from the PFA program, the review of he Company's Earthco facilities is back on the normal procedural audit path of the Company's tax returns. Through December 31, 2004, based on its ownership percentage, the Company has used or carried forward $550 million of tax credits generated by Earthco facilities.

If these credits were disallowed, Florida Progress' one time exposure for cash tax payments would be $64 million (excluding interest), and earnings and equity would be reduced by $550 million, excluding interest.

On October 29, 2004, Progress Energy received the IRS field auditors' report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and that the tax credits generated by those facilities should be disallowed. The Company disagrees with the field audit team's factual findings and believes that the Earthco facilities were placed in service before July 1, 1998. The Company also believes that the report applies an inappropriate legal standard concerning what constitutes "placed in service." The Company intends to contest the field auditors' findings and their proposed disallowance of the tax credits.

Because of the disagreement between the Company and the field auditors as to the proper legal standard to apply, the Company believes that it is appropriate and helpful to have this issue reviewed by the National Office of the IRS, just as the National Office reviewed the issues involving chemical change. Therefore, the Company is asking the National office to clarify the legal standard and has initiated this process with the National Office. The Company believes that the appeals process, including proceedings before the National Office, could take up to two years to complete, however, it cannot control the actual timing of resolution and cannot predict the outcome of this matter.

In management's opinion, the Company is complying with all the necessary requirements to be allowed such credits under Section 29, and, although it cannot provide certainty, it believes that it will prevail in these matters. Accordingly, while the Company has adjusted its synthetic fuel production for 2004 in response to the effects of the hurricane damage on its 2004 tax liability, it has no current plans to alter its synthetic fuel production schedule for future years as a result of the IRS field auditors' report. However, should the Company fail to prevail in these matters, there could be a material liability for previously taken Section 29 tax credits, with a material adverse impact on earnings and cash flows.

PROPOSED ACCOUNTING RULES FOR UNCERTAIN TAX POSITIONS

In July 2004, the FASB stated that it plans to issue an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes," that would address the accounting for uncertain tax positions. The FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits.

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 of the Code. 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 the Company's synthetic fuel operations. Progress Energy is providing information in connection with this investigation. The Company cannot predict the outcome of this matter.

SALE OF PARTNERSHIP INTEREST

In June 2004, the Company through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, 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 Company's book value of the interests sold totaled approximately $3 million. The Company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007 and approximately $8 million through the second quarter of 2008. 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.

IMPACT OF CRUDE OIL PRICES

Although the Internal Revenue Code Section 29 tax credit program is expected to continue through 2007, recent unprecedented and unanticipated increases in the price of oil could limit the amount of those credits or eliminate them altogether for one or more of the years following 2004. 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 value (the "Threshold Price"), the amount of 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 tax credits are eliminated for that year. For 2003, the Threshold Price was $50.14 per barrel and the Phase Out Price was $62.94 per barrel. The Threshold Price and the Phase Out Price are adjusted annually for inflation.

If the Annual Average Price falls between the Threshold Price and the Phase Out Price for a year, the amount by which Section 29 tax credits are reduced will depend on where the Average Annual Price falls in that continuum. For example, for 2003, if the Annual Average Price had been $56.54 per barrel, there would have been a 50% 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 its calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2003 was published in April 2004.

Although the official notice for 2004 is not expected to be published until April of 2005, the Company does not believe that the Annual Average Price for 2004 will reach the Threshold Price for 2004. Consequently, the Company does not expect the amount of its 2004 Section 29 tax credits to be adversely affected by oil prices.

The Company cannot predict with any certainty the Annual Average Price for 2005 or beyond. Therefore, it cannot predict whether the price of oil will have a material effect on it synthetic fuel business after 2004. However, if during 2005 through 2007, oil prices remain at historically high levels or increase, the Company's synthetic fuel business may be adversely affected for those years and, depending on the magnitude of such increases in oil prices, the adverse affect for those years could be material and could have an impact on the Company's results of operations and synthetic fuel production plans.

5. Other Legal Matters

Florida Progress and PEF are involved in various other claims and legal actions arising in the ordinary course of business, some of which involve claims for substantial amounts. Where appropriate, accruals have been made in accordance with SFAS No. 5, "Accounting for Contingencies," to provide for such matters. Florida Progress and PEF believe the ultimate disposition of these matters will not have a material adverse effect upon either Company's consolidated and PEF's financial position or results of operations.

22. SUBSEQUENT EVENTS

Sale of Progress Rail

On February 18, 2005, Progress Energy announced it has entered into a definitive agreement to sell Progress Rail to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Gross cash proceeds from the transaction will be $405 million, subject to working capital adjustments. The sale is expected to close by mid-2005, and is subject to various closing conditions customary to such transactions. Proceeds from the sale are expected to be used to reduce debt. The Company expects to report Progress Rail as a discontinued operation in the first quarter of 2005. The carrying amounts for the assets and liabilities of the discontinued operations disposal group included in the Consolidated Balance Sheets at December 31, are as follows:

(in millions)	**2004**	2003
Total current assets	**$ 378**	$ 373
Total property, plant & equipment (net)	**202**	184
Total other assets	**28**	64
Total current liabilities	**156**	114
Total long-term liabilities	**3**	3
Total capitalization	**449**	504

Cost Management Initiative

On February 28, 2005, as part of a previously announced cost management initiative, the executive officers of Progress Energy approved a workforce restructuring. The restructuring is expected to be completed in September of 2005. In addition to the workforce restructuring, the cost management initiative includes a voluntary enhanced retirement program.

In connection with the cost management initiative, the Company expects to incur one-time pre-tax charges of approximately $54 million. Approximately $9 million of that amount relates to payments for severance benefits, and will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $45 million will be recognized in the second quarter of 2005 and relates primarily to post-retirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program. The total cost management initiative charges could change significantly depending upon how many eligible employees elect early retirement under the voluntary enhanced retirement program and the salary, service years and age of such employees.

23. SUPPLEMENTAL INFORMATION FOR OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following supplemental unaudited information regarding the Company's oil and gas activities is presented pursuant to disclosure requirements of SFAS No. 69 "Disclosures About Oil and Gas Producing Activities."

A. Capitalized Costs

The aggregate amounts of costs capitalized for oil and gas producing activities, and related aggregate amounts of accumulated depreciation, depletion and amortization (See Notes 4A and 5B), at December 31 follows:

(in millions)	2004	2003
Capitalized Costs -		
Proved Properties being amortized	$ 281	$ 352
Unproved Properties not being amortized	55	60
	336	412
Less - Accumulated depreciation, depletion, and amortization	(52)	(35)
Net Capitalized Costs	$ 284	$ 377

B. Costs Incurred

There were no oil or gas exploration costs for the years ended 2004, 2003 and 2002. The following costs (in millions) were included in oil and gas producing activities during the years ended December 31,

(in millions)	2004	2003	2002
Property acquisition	$ 7	$ 169	$ 141
Development	95	105	16
Total Costs Incurred	$ 102	$ 274	$ 157

C. Results of Operations

The following summarizes the results of operations for the Company's oil and gas producing activities:

(in millions)	2004	2003	2002
Revenues - Sales	$ 151	$ 107	$ 36
Less:			
Production (lifting) costs	28	16	7
Depreciation, depletion, and amortization, and valuation provisions	41	33	11
Pretax Operating Income	82	58	18
Income tax expenses	33	19	6
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 49	$ 39	$ 12

D. Estimated Quantities of Oil and Gas Reserves

At December 31, 2004, the Company had proved oil and gas reserves of 247 Bcfe estimated by Netherland Sewell & Associates, Inc., an independent engineering firm. These reserves are located entirely within the United States. Estimated net quantities of proven oil and gas reserves at December 31 for each of the last three years were as follows in Bcfe. Reserve quantities stated in Bcfe use an energy conversion factor of six units of gas for every one unit of oil.

January 1, 2002	69
Acquisitions	**87**
Extensions and discoveries	62
Production	(13)
December 31, 2002	205
Acquisitions	189
Extensions and discoveries	65
Production	(25)
Sales	(76)
December 31, 2003	**358**
Acquisitions	**12**
Extensions and discoveries	**58**
Production	**(30)**
Sales	**(151)**
December 31, 2004	**247**
Proved Developed Reserves included above:	
At December 31, 2002	179
At December 31, 2003	225
At December 31, 2004	**137**

E. Standardized Measure of Discounted Future Net Cash Flows (SMOG)

The following standardized disclosures required by FASB do not represent the results of operations based on its historical financial statements. In addition to requiring different determinations of revenue and costs, the disclosures exclude the impact of interest expense and corporate overhead. The following table sets forth, at December 31, 2004, the proven reserves and the present value, discounted at an annual rate of 10%, of future net revenues (revenues less production and development cost) attributable to these reserves.

(in millions)	2004 Proved Developed	2004 Proved Un-developed	2004 Total Proved	2003 Proved Developed	2003 Proved Un-developed	2003 Total Proved	2002 Proved Developed	2002 Proved Un-developed	2002 Total Proved
Future Cash Inflows	$ 806	$ 648	$ 1,454	$ 1,283	$ 781	$ 2,064	$ 480	$ 419	$ 899
Less: Future production costs	277	182	459	357	203	560	138	100	238
Future development costs	24	133	157	40	122	162	7	58	65
Future income tax expense at 36%	182	120	302	319	164	483	121	94	215
Future Net Cash Flows	323	213	536	567	292	859	214	167	381
Less: annual discount	120	115	235	300	195	495	79	83	162
Standardized measure of discounted future net cash flows	$ 203	$ 98	$ 301	$ 267	$ 97	$ 364	$ 135	$ 84	$ 219

For purposes of determining the above cash flows, estimates were made of quantities of proved reserves and the periods during which they are expected to produce. Future cash flows were computed by applying year-end prices to estimated annual future production from our proved oil and gas reserves. The year-end prices for crude oil and natural gas used in the estimation were $45.64 per Bbl and $6.21 per MMbtu, based on a December 31, 2004, Henry Hub spot market price. Future development and production costs were computed by applying year-end costs expected to be incurred in producing and further developing the proved reserves. The estimated future net cash flows were computed by application of a 10% per annum discount factor. The calculations assume the continuation of existing economic, operating and contractual conditions. Other assumptions of equal validity could give rise to substantially different results.

For the years ended, December 31, 2003 and 2002, $166 million of the increase to the SMOG was due to acquisition of reserves. For the years ended, December 31, 2004 and 2003, $166 million of the change was due to the sale of reserves and $53 million was due to increased development costs.

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for Florida Progress is as follows:

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2004				
Operating revenues	**$ 1,308**	**$ 1,495**	**$ 1,670**	**$1,462**
Operating income	**103**	**181**	**260**	**157**
Net income	**55**	**135**	**148**	**136**
Year ended December 31, 2003				
Operating revenues	$ 1,215	$ 1,207	$ 1,391	$ 1,195
Operating income	126	122	193	64
Net income	92	114	174	67

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. Certain reclassifications have been made to previously reported amounts to conform to the current year's presentation. Fourth quarter 2004 includes a goodwill impairment charge related to the Company's coal mining business of $8 million before and after tax (See Note 9) and a $31 million after-tax gain on the sale of natural gas assets (See Note 4A). Fourth quarter 2004 also includes the recording of $47 million of Section 29 tax credits (See Note 21E). Third quarter 2004 includes the reversal of $55 million of Section 29 tax credits (See Note 21E). Fourth quarter 2003 includes an impairment related to Kentucky May of $15 million ($10 million after-tax) (See Note 10).

Summarized quarterly financial data for PEF is as follows:

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2004				
Operating revenues	**$ 784**	**$ 860**	**$ 1,029**	**$852**
Operating income	**103**	**157**	**244**	**114**
Net income	**50**	**84**	**140**	**61**
Year ended December 31, 2003				
Operating revenues	$ 728	$ 767	$ 904	$ 753
Operating income	135	116	184	93
Net income	71	62	115	49

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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARDS OF DIRECTORS OF FLORIDA PROGRESS COPORATION AND FLORIDA POWER ORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

We have audited the consolidated financial statements of Florida Progress Corporation and its subsidiaries (Florida Progress) and the financial statements of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, and have issued our reports thereon dated March 7, 2005 (which express an unqualified opinion and include an explanatory paragraph concerning the adoption of a new accounting principle in 2003); such reports are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of Florida Progress and PEF listed in Item 15. These financial statement schedules are the responsibility of Florida Progress' and PEF's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 7, 2005

FLORIDA PROGRESS CORPORATION
Schedule II - Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expense	Other Additions	Deductions (a)	Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:					
DECEMBER 31, 2004					
Uncollectible accounts	**$ 15**	**$ 10**	**$ –**	**$ (6)**	**$ 19**
Fossil dismantlement Reserve	**143**	**1**	**–**	**–**	**144**
Nuclear refueling outage reserve	**2**	**10**	**–**	**–**	**12**
DECEMBER 31, 2003					
Uncollectible accounts	$ 28	$ 12	$ –	$ (25)	$ 15
Fossil dismantlement reserve	142	1	–	–	143
Nuclear refueling outage reserve	10	8	–	(16) (b)	2
DECEMBER 31, 2002					
Uncollectible accounts	$ 26	$ 14	$ –	$ (12)	$ 28
Fossil dismantlement reserve	141	1	–	–	142
Nuclear refueling outage reserve	–	10	–	–	10

(a) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for uncollectible accounts, such deductions are reduced by recoveries of amounts previously written off.
(b) Represents payments of actual expenditures related to the outages.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA
Schedule II - Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning Of Period	Additions Charged to Expense	Other Additions	Deductions (a)	Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:					
DECEMBER 31, 2004					
Uncollectible accounts	**$ 2**	**$ 5**	**$ –**	**$ (5)**	**$ 2**
Fossil dismantlement Reserve	**143**	**1**	**–**	**–**	**144**
Nuclear refueling outage reserve	**2**	**10**	**–**	**–**	**12**
DECEMBER 31, 2003					
Uncollectible accounts	$ 2	$ 5	$ –	$ (5)	$ 2
Fossil dismantlement reserve	142	1	–	–	143
Nuclear refueling outage reserve	10	8	–	(16) (b)	2
DECEMBER 31, 2002					
Uncollectible accounts	$ 3	$ 3	$ –	$ (4)	$ 2
Fossil dismantlement reserve	141	1	–	–	142
Nuclear refueling outage reserve	–	10	–	–	10

(a) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for uncollectible accounts, such deductions are reduced by recoveries of amounts previously written off.
(b) Represents payments of actual expenditures related to the outages.

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Florida Progress Corporation

Pursuant to the Securities Exchange Act of 1934, Florida Progress carried out an evaluation, and with the participation of its management, including Florida Progress' Chief Executive Officer and Chief Financial Officer, of the effectiveness of Florida Progress' disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, Florida Progress' Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by Florida Progress (including its consolidated subsidiaries) in the reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to Florida Progress' management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in Florida Progress' internal control over financial reporting during the quarter ended December 31, 2004 that has materially affected, or is reasonably like to materially affect, Florida Progress' internal control over financial reporting.

The Company notes, however, that as part of the Company's review of internal controls, the Company will be implementing changes related to capitalization practices for PEF's Energy Delivery business unit effective January 1, 2005. A review of these practices indicated that in the areas of outage and emergency work, not associated with major storm and allocation of indirect costs, PEF should revise the way that it estimates the amount of capital costs associated with such work. The changes for 2005 in this area include use of more detailed accounts to segregate capital and expense items, more regular testing of accounting estimates and realignment of certain accounting functions. This matter is also discussed in Note 8D to the Florida Progress Corporation Consolidated Financial Statements.

Progress Energy Florida

Pursuant to the Securities Exchange Act of 1934, PEF carried out an evaluation, and with the participation of its management, including PEF's Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEF's disclosure controls and procedures (as defined under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, PEF's Chief Executive Officer and Chief Financial Officer concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by PEC in the reports that it files or submits under the Exchange Act, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to PEF's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in PEF's internal control over financial reporting during the quarter ended December 31, 2004 that has materially affected, or is reasonably like to materially affect, PEF's internal control over financial reporting.

PEF notes, however, that as part of its review of internal controls, PEF will be implementing changes related to capitalization practices for its Energy Delivery business unit effective January 1, 2005. A review of these practices indicated that in the areas of outage and emergency work, not associated with major storm and allocation of indirect costs, PEF should revise the way that it estimates the amount of capital costs associated with such work. The changes for 2005 in this area include use of more detailed accounts to segregate capital and expense items, more regular testing of accounting estimates and realignment of certain accounting functions. This matter is also discussed in Note 8D to the PEF Financial Statements.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

The information called for by ITEM 10 is omitted pursuant to Instruction I (2) (c) to Form 10-K (Omission of Information by Certain Wholly owned Subsidiaries).

ITEM 11. EXECUTIVE COMPENSATION

The information called for by ITEM 11 is omitted pursuant to Instruction I (2) (c) to Form 10-K (Omission of Information by Certain Wholly owned Subsidiaries).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information called for by ITEM 12 is omitted pursuant to Instruction I (2) (c) to Form 10-K (Omission of Information by Certain Wholly owned Subsidiaries).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information called for by ITEM 13 is omitted pursuant to Instruction I (2) (c) to Form 10-K (Omission of Information by Certain Wholly owned Subsidiaries).

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit and Corporate Performance Committee of Progress Energy Inc.'s, Board of Directors ("Audit Committee") has actively monitored all services provided by its independent auditors, Deloitte & Touche LLP, the member firms of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte") and the relationship between audit and non-audit services provided by Deloitte. Progress Energy, Inc. has adopted policies and procedures for approving all audit and permissible non-audit services rendered by Deloitte, and the fees billed for those services. The Audit Committee specifically pre-approved the use of Deloitte for audit, audit-related, tax and non-audit services, subject to certain limitations. Audit and audit-related services include assurance and related activities, services associated with internal control reviews, reports related to regulatory filings, certain due diligence services pertaining to acquisitions, consultations on dispositions and discontinued operations, employee benefit plan audits and general accounting and reporting advice. The preapproval policy provides that any audit and audit-related services covered by the blanket preapproval whose project scope could not be defined at the time of blanket approval that will require expenditure of over $50,000 will require individual approval by the Audit Committee in advance of Deloitte being engaged to render such services. Once the cumulative total of those projects less than $50,000 exceeds $500,000 for the year, each subsequent project, regardless of amount, must be approved individually in advance by the Audit Committee.

The preapproval policy requires management to obtain specific preapproval from the Audit Committee for the use of Deloitte for any permissible non-audit services, which, generally, are limited to tax services including, tax compliance, tax planning, and tax advice services such as return review and consultation and assistance. Other types of permissible non-audit services will be considered for approval only in rare circumstances, which may include proposed services that provide significant economic or other benefits to the Company. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible non-audit services provided during a fiscal year that (i) do not aggregate more than 5% of the total fees paid to Deloitte for all services rendered during that fiscal year and (ii) were not recognized as non-audit services at the time of the engagement must be brought to the attention of the Controller for prompt submission to the Audit Committee for approval. These "de minimis" non-audit services must be approved by the Audit Committee or its designated representative before the completion of the project. The policy also requires management to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The Audit Committee will assess the adequacy of this procedure on an annual basis and revise it accordingly.

Set forth in the table below is certain information relating to the aggregate fees billed by Deloitte for professional services rendered to Florida Progress and Progress Energy Florida for the fiscal years ended December 31, 2004 and December 31, 2003.

Florida Progress

	2004	2003
Audit Fees	$ 2,799,000	$ 1,194,000
Audit-Related Fees	$ 104,000	$ 78,000
Tax Fees	$ 182,000	$ 31,000
All Other Fees	$ 2,000	$ 4,000
	$ 3,087,000	$ 1,307,000

Progress Energy Florida

	2004	2003
Audit Fees	$ 1,394,000	$ 598,000
Audit-Related Fees	$ 3,000	$ 8,000
Tax Fees	$ 165,000	$ 24,000
All Other Fees	$ 1,000	$ 3,000
	$ 1,563,000	$ 633,000

Audit Fees include fees billed for services rendered in connection with (i) the audits of the annual financial statements of the Company and its SEC reporting subsidiary (Progress Energy Florida) (ii) the reviews of the financial statements included in the Quarterly Reports on Form 10-Q of the Company and its SEC reporting subsidiary (iii) the audits of the financial statements of certain non-reporting subsidiaries of the Company; and (iv) SEC filings, accounting consultations arising as part of the audits and comfort letters.

Audit-Related Fees include fees billed for (i) audits of the financial statements of certain of the Company's non-reporting subsidiaries; (ii) special procedures and letter reports, (iii) benefit plan audits when fees are paid by the Company rather than directly by the plan and (iv) accounting consultations for prospective transactions not arising directly from the audits.

Tax Fees includes fees billed for tax compliance matters and tax planning and advisory services.

All Other Fees includes fees billed for rate case assistance and utility accounting training.

The Audit Committee has concluded that the provision of the non-audit services listed above as "All Other Fees" is compatible with maintaining Deloitte's independence.

None of the services provided were approved by the Audit Committee pursuant to the de minimis waiver provisions described above.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K FOR FLORIDA PROGRESS AND PROGRESS ENERGY FLORIDA

1. Financial Statements, notes to Financial Statements and reports thereon of DELOITTE & TOUCHE LLP and KPMG LLP are found in ITEM 8 "Financial Statements and Supplementary Data" herein.

2. Financial Statement Schedules and the report thereon of DELOITTE & TOUCHE LLP are found at ITEM 8 "Financial Statements and Supplementary Data" herein.

3. Exhibits filed herewith:

Number	Exhibit	Florida Progress	PEF
*2	Amended and Restated Agreement and Plan of Exchange by and among Carolina Power & Light Company, Florida Progress Corporation and CP&L Energy, Inc., dated as of August 22, 1999, amended and restated as of March 3, 2000 (filed as Annex A to the Florida Progress preliminary proxy statement on Schedule 14A, as filed with the SEC on March 6, 2000).	X	
*3. (a)	Amended Articles of Incorporation, as amended, of Florida Power Corporation. (Filed as Exhibit 3(a) to the Progress Energy Florida Form 10-K for the year ended December 31, 1991, as filed with the SEC (File No. 1-3274) on March 30, 1992.)		X
*3. (b)	Restated Articles of Incorporation, as amended, of Florida Progress (filed as Exhibit 3(a) to Florida Progress' Form 10-K for the year ended December 31,1991, as filed with the SEC on March 30, 1992).	X	
*3. (c)	Bylaws of Florida Progress, as amended September 19, 2003. (filed as Exhibit 3(ii) to the Florida Progress Form 10-Q for the quarter ended September 30, 2003, as filed with the SEC on November 12, 2003).	X	
3. (d)	Bylaws of Progress Energy Florida, as amended October 1, 2001.		X
*4. (a)	Indenture, dated as of January 1, 1944 (the "Indenture"), between Florida Power Corporation and Guaranty Trust Company of New York and The Florida National Bank of Jacksonville, as Trustees (filed as Exhibit B-18 to Florida Power's Registration Statement on Form A-2 (No. 2-5293) filed with the SEC on January 24, 1944).	X	X

*4. (b)	Twenty-Ninth Supplemental Indenture, dated as of September 1, 1982, between Florida Power Corporation and Morgan Guaranty Trust Company of New York and Florida National Bank, as Trustees, with reference to the modification and amendment of the Indenture (filed as Exhibit 4(c) to Florida Power Corporation's Registration Statement on Form S-3 (No. 2-79832) filed with the SEC on September 17, 1982).	X	X
*4. (c)	Seventh Supplemental Indenture, dated as of July 1, 1956, between Florida Power Corporation and Guaranty Trust Company of New York and The Florida National Bank of Jacksonville, as Trustees, with reference to the modification and amendment of the Indenture (filed as Exhibit 4(b) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991).	X	X
*4. (d)	Eighth Supplemental Indenture, dated as of July 1, 1958, between Florida Power Corporation and Guaranty Trust Company of New York and The Florida National Bank of Jacksonville, as Trustees, with reference to the modification and amendment of the Indenture (filed as Exhibit 4(c) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991).	X	X
*4. (e)	Sixteenth Supplemental Indenture, dated as of February 1, 1970, between Florida Power Corporation and Morgan Guaranty Trust Company of New York and The Florida National Bank of Jacksonville, as Trustees, with reference to the modification and amendment of the Indenture (filed as Exhibit 4(d) to Florida Power Corporation's Registration Statement on Form S-3 (No. 33-16788) filed with the SEC on September 27, 1991).	X	X
*4. (f)	Rights Agreement, dated as of November 21, 1991, between Florida Progress and Manufacturers Hanover Trust Company, including as Exhibit A the form of Rights Certificate (filed as Exhibit 4(a) to Florida Progress' Form 8-K dated November 21, 1991, as filed with the SEC on November 27, 1991).	X	
*4. (g)	Thirty-Eighth Supplemental Indenture dated as of July 25, 1994, between Florida Power Corporation and First Chicago Trust Company of New York, as successor Trustee, Morgan Guaranty Trust Company of New York, as resigning Trustee, and First Union National Bank of Florida, as resigning Co-Trustee, with reference to confirmation of First Chicago Trust Company of New York as successor Trustee under the Indenture (filed as exhibit 4(f) to Florida Power's Registration Statement on Form S-3 (No. 33-55273) as filed with the SEC on August 29, 1994).	X	X

*4.(h)	Thirty-Ninth Supplemental Indenture dated as of July 1, 2001 between Florida Power Corporation and First Chicago Trust Company of New York, as Trustee (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on July 23, 2001).		X
*4.(i)	Fortieth Supplemental Indenture dated as of July 1, 2002 between Progress Energy Florida and First Chicago Trust Company of New York (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 18, 2003).		X
*4.(j)	Forty-First Supplemental Indenture, dated as of February 1, 2003 between Progress Energy Florida and First Chicago Trust Company of New York, as successor Trustee (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 21, 2003).		X
*4.(k)	Forty-second Supplemental Indenture, dated as of April 1, 2003, from Progress Energy Florida, Inc. to First Chicago Trust Company of New York (Resigning Trustee) and Bank One, N.A. (Successor Trustee), supplement to Indenture dated as of January 1, 1944, as supplemented (filed as Exhibit 4 to Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 filed with the SEC on September 11, 2003).		X
*4.(l)	Forty-third Supplemental Indenture, dated as of November 1, 2003, between Progress Energy Florida, Inc. and JPMorgan Chase Bank, as Trustee (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on November 21, 2003).		X
4.(m)	Forty-fourth Supplemental Indenture, dated as of August 1, 2004 from Progress Energy Florida, Inc. to JPMorgan Chase Bank, as Trustee, supplement to Indenture dated as of January 1, 1944, as supplemented.		X
*4. (n)	Form of Certificate representing shares of Florida Progress Common Stock (filed as Exhibit 4(b) to the Florida Progress Form 10-K for the year ended December 31, 1996, as filed with the SEC on March 27, 1997).	X	
10.(a)(1)	Amendment and Restatement, dated March 30, 2004 to Progress Energy Florida, Inc.'s 364-Day Revolving Credit Agreement dated April 1, 2003.		X
*10.(a)(2)	Progress Energy Florida 364-Day $200,000,000 Credit Agreement dated as of April 1, 2003 (filed as Exhibit 10(ii) to Progress Energy Florida Form 10-Q for the quarter ended March 31, 2003).		X
*10.(a)(3)	Progress Energy Florida 3-Year $200,000,000 Credit Agreement, dated as of April 1, 2003 (filed as Exhibit 10(iii) to the Progress Energy Florida Form 10-Q for the quarter ended March 31, 2003).		X

+*10. (b)(1)	Executive Optional Deferred Compensation Plan (filed as Exhibit 10.(c) to the Florida Progress Form 10-K for the year ended December 31, 1996 as filed with the SEC on March 27, 1997).	X	X
+*10.(b)(2)	Management Incentive Compensation Plan of Florida Progress Corporation, as amended December 14, 1999 (filed as Exhibit 10.(a) to the Florida Progress Form 10-K for the year ended December 31, 1999, as filed with the SEC on March 30, 2000).	X	X
+*10.(b)(3)	Progress Energy Florida Management Incentive Compensation Plan, effective January 1, 2001 (filed as Exhibit 10b(25) to Annual Report on Form 10-K for the year ended December 31, 2000, File No. 1-15929 and No. 1-3382).		X
+*10. (b)(4)	Florida Progress Supplemental Executive Retirement Plan, as amended and restated effective February 20, 1997 (filed as Exhibit 10.(e) to the Florida Progress Form 10-K for the year ended December 31, 1999, as filed with the SEC on March 30, 2000).	X	X
-+*10.(b)(5)	Resolutions of the Board of Directors of Carolina Power & Light Company dated May 8, 1991, amending the Directors Deferred Compensation Plan (filed as Exhibit 10(b), File No. 33-48607).	X	
-+*10.(b)(6)	Carolina Power & Light Company Restricted Stock Agreement, as approved January 7, 1998, pursuant to Carolina Power & Light Company's 1997 Equity Incentive Plan (filed as Exhibit No. 10 to Carolina Power & Light Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 1998, File No. 1-3382).	X	X
-+*10.(b)(7)	Performance Share Sub-Plan of the Carolina Power & Light Company 1997 Equity Incentive Plan, as amended January 1, 2001 (filed as Exhibit 10b(11) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2001).	X	X
+*10.(b)(8)	1997 Equity Incentive Plan, Amended and Restated as of September 26, 2001 (filed as Exhibit 4.3 to Progress Energy, Inc. Form S-8 dated September 27, 2001, File No. 1-3382).	X	X
+*10.(b)(9)	Progress Energy, Inc. Form of Stock Option Agreement (filed as Exhibit 4.4 to Form S-8 dated September 27, 2001, File No. 333-70332).	X	X
+*10.(b)(10)	Progress Energy, Inc. Form of Stock Option Award (filed as Exhibit 4.5 to Form S-8 dated September 27, 2001, File No. 333-70332).	X	X

+*10.(b)(11)	Progress Energy, Inc. 2002 Equity Incentive Plan, dated July 10, 2002 (filed as Exhibit 10(i) to Quarterly Report on form 10-Q for the quarterly period ended September 30, 2002, File No. 1-08349 and 1-03274).	X	X
+*10.(b)(12)	Amended Management Incentive Compensation Plan of Progress Energy, Inc., effective January 1, 2005 (filed as Exhibit 10(i) to current report on Form 8-K dated December 13, 2004, File Nos. 1-3382, 1-3274, 1-15929 and 1-8349).	X	X
+*10.(b)(13)	Progress Energy, Inc. Amended and Restated Management Deferred Compensation Plan, Adopted as of January 1, 2000, as Revised and Restated effective January 1, 2005, (filed as Exhibit 10c(11) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X
+*10.(b)(14)	Progress Energy, Inc. Management Change-in-Control Plan Amended and Restated Effective as of January 1, 2005 (filed as Exhibit 10c(12) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X
+*10.(b)(15)	Amended Performance Share Sub-Plan of the 2002 Progress Energy, Inc. Equity Incentive Plan effective as of January 1, 2005 (filed as Exhibit 10c(13) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X
+*10.(b)(16)	Form of Deferred Compensation Plan for Directors—Method of Payment Agreement of Progress Energy, Inc. Effective January 1, 2005 (filed as Exhibit 10(ii) to Current Report on Form 8-K dated December 13, 2004, File Nos. 1-3382, 1-3274, 1-15929 and 1-8349).	X	X
+*10.(b)(17)	Amended and Restated Progress Energy, Inc. Restoration Retirement Plan effective as of January 1, 2005 (filed as Exhibit 10c(15) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X
+*10.(b)(18)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., amended effective January 1, 2005 (filed as Exhibit 10c(16) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X
+*10.(b)(19)	Amended Non-Employee Director Stock Unit Plan of Progress Energy, Inc. effective as of January 1, 2005 (filed as Exhibit 10(iii) to Current Report on Form 8-K dated December 13, 2004, File Nos. 1-3382, 1-3274, 1-15929 and 1-8349).	X	X
+*10.(b)(20)	Form of Progress Energy, Inc. Restricted Stock Agreement pursuant to the 2002 Progress Energy, Inc. Equity Incentive Plan, as amended July 2002 (filed as Exhibit 10c(18) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X

+*10.(b)(21)	Employment Agreement dated August 1, 2000 between Carolina Power & Light Company and William S. "Skip" Orser (filed as Exhibit 10(ii) to the Progress Energy, Inc. Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).		X
+*10.(b)(22)	Form of Employment Agreement dated August 1, 2000 between CP&L Service Company LLC and Peter M. Scott III(filed as Exhibit 10(v) to the Progress Energy, Inc. Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X
+*10.(b)(23)	Form of Employment Agreement dated August 1, 2000 between Carolina Power & Light Company and (i) Fred Day IV, (ii) C.S. "Scotty" Hinnant, and (iii) E. Michael Williams (filed as Exhibit 10(vi) to the Progress Energy, Inc. Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	
+*10.(b)(24)	Employment Agreement dated November 30, 2000 between Carolina Power & Light Company, Florida Power Corporation and H. William Habermeyer (filed as Exhibit 10.(b)(32) to Annual Report on Form 10-K for the year ended December 31, 2000).	X	X
+*10.(b)(25)	Form of Employment Agreement between Progress Energy Florida, Inc. and Jeffrey J. Lyash, effective December 2003. (filed as Exhibit 10c(27) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2002, File No. 1-15929 and No. 1-3382).		X
+*10.(b)(26)	Form of Employment Agreement effective January 2003 between Progress Energy Service Company LLC and John R. McArthur (filed as Exhibit 10c(27) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2002, File No. 1-15929 and No. 1-3382).	X	X
+*10.(b)(27)	Employment Agreement dated October 1, 2003 between Progress Energy Service Company LLC and Geoffrey S. Chatas (filed as Exhibit 10c(28) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2003, File No. 1-15929 and No. 1-3382).	X	X
+*10.(b)(28)	Form of Employment Agreement dated January 1, 2005 between Progress Energy Carolinas, Inc. and William D. Johnson (filed as Exhibit 10c(29) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X

*10.(c)(1)	Agreement dated November 18, 2004 between Pipeline, Ltd., Progress Energy, Inc. and EnCana Oil & Gas (USA), Inc. for the sale of certain oil and gas interests and related assets located in Texas (filed as Exhibit 10d(1) to the Progress Energy, Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2004).	X	X
*10(c)(2)	Precedent and Related Agreements among Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), Southern Natural Gas Company ("SNG"), Florida Gas Transmission Company ("FGT"), and BG LNG Services, LLC ("BG"), including: a) Precedent Agreement by and between SNG and PEF, dated December 2, 2004; b) Gas Sale and Purchase Contract between BG and PEF, dated December 1, 2004; c) Interim Firm Transportation Service Agreement by and between FGT and PEF, dated December 2, 2004; d) Letter Agreement between FGT and PEF, dated December 2, 2004 and Firm Transportation Service Agreement by and between FGT and PEF to be entered into upon satisfaction of certain conditions precedent; e) Discount Agreement between FGT and PEF, dated December 2, 2004; f) Amendment to Gas Sale and Purchase Contract between BG and PEF, dated January 28, 2005; and g) Letter Agreement between FGT and PEF, dated January 31, 2005, (filed as Exhibit 10.1 to Current Report on Form 8-K/A filed March 15, 2005). (Confidential treatment has been requested for portions of this exhibit. These portions have been omitted from the above-referenced Current Report and submitted separately to the SEC.)	X	X
12	Statement of Computation of Ratios	X	X
23. (a)	Consent of Deloitte & Touche LLP	X	X

X Exhibit is filed for that respective company.
* Incorporated herein by reference as indicated.
+ Management contract or compensation plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.
- Sponsorship of this management contract or compensation plan or arrangement was transferred by Carolina Power & Light Company to Progress Energy, Inc., effective August 1, 2000.

RISK FACTORS

In this section, unless the context indicates otherwise, references to "our," "we," "us" or similar terms refer to Progress Energy Florida, Inc. The following section is applicable most directly to Progress Energy Florida. However, the risk factors below are substantially applicable to our corporate parent, Florida Progress. Risk related to synthetic fuel operations are primarily related to Florida Progress Corporation.

Investing in our securities involves risks, including the risks described below, that could affect the energy industry, as well as us and our business. Most of the business information as well as the financial and operational data contained in our risk factors are updated periodically in the reports we file with the SEC. Although we have tried to discuss key factors, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Before purchasing our securities, you should carefully consider the following risks and the other information in this Annual Report, as well as the documents we file with the SEC from time to time. Each of the risks described below could result in a decrease in the value of our securities and your investment therein.

Risks Related to the Energy Industry

We are subject to fluid and complex government regulations that may have a negative impact on our business, financial condition and results of operations.

We are subject to comprehensive regulation by several federal, state and local regulatory agencies, which significantly influence our operating environment and may affect our ability to recover costs from utility customers. We are subject to regulatory oversight with respect to, among other things, rates and service for electric energy sold at retail, retail service territory and issuances of securities. In addition our operating utilities are subject to regulation with respect to transmission and sales of wholesale power, accounting and certain other matters. We are also required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

The 108th Congress spent much of 2004 working on a comprehensive energy bill. While that legislation passed the House, the Senate failed to pass the legislation in 2004. There will probably be an effort to resurrect the legislation in 2005. The legislation would have further clarified the Federal Energy Regulatory Commission's ("FERC") role with respect to Standard Market Design and mandatory Regional Transmission Organizations ("RTOs") and would have repealed the Public Utility Holding Company Act of 1935 ("PUHCA"). We cannot predict the outcome or impact of the proposed or any future energy bill.

FERC, the U.S. Nuclear Regulatory Commission ("NRC"), the U.S. Environmental Protection Agency ("EPA") and the Florida Public Service Commission ("FPSC") regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. Although we are not a registered holding company under PUHCA, we are subject to many of the regulatory provisions of PUHCA.

We are unable to predict the impact on our business and operating results from future regulatory activities of these federal, state and local agencies. Changes in regulations or the imposition of additional regulations could have a negative impact on our business, financial condition and results of operations.

We are subject to numerous environmental laws and regulations that require significant capital expenditures, increase our cost of operations, and which may impact or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the outcome (financial or operational) of any related litigation that may arise.

In addition, we may be a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs.

Congress is currently considering further legislation that would require reductions in air emissions of NOx, SO_2, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs which could be material to our consolidated financial position or results of operations. However, we cannot predict the outcome, costs or impact of this matter. In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The EPA's proposal requires 29 jurisdictions, including North Carolina, South Carolina, Georgia and Florida, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. The rule is expected to become final in March 2005.

See additional discussion of these environmental matters in Note 20 to the Consolidated Financial Statements.

We cannot assure you that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our results of operations.

The uncertain outcome regarding the timing, creation and structure of regional transmission organizations, or RTOs, may materially impact our results of operations, cash flows or financial condition.

Congress, FERC, and the state utility regulators have paid significant attention in recent years to transmission issues, including the possibility of regional transmission organizations. While these deliberations have not yet resulted in significant changes to our utilities' transmission operations, they cast uncertainty over those operations, which constitute a material portion of our assets.

For the last several years, the FERC has supported independent RTOs and has indicated a belief that it has the authority to order transmission-owning utilities to transfer operational control of their transmission assets to such RTOs. Many state regulators, including most regulators in the Southeast, have expressed skepticism over the potential benefits of RTOs and generally disagree with the FERC's interpretation of its authority to mandate RTOs. In July 2002, the FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). In its current form, SMD NOPR could materially alter the manner in which transmission and generation services are provided and paid for, and includes provisions for mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. We cannot predict the outcome or timing of any final rules or the effect that they may have on the GridFlorida proceedings currently ongoing before the FERC.

At the state level, significant uncertainty exists with respect to what action, if any, the FPSC will ultimately take. The Company has $4 million invested in GridFlorida related to startup costs at December 31, 2004. These amounts are included as a regulatory asset at December 31, 2004. The Company expects to recover these startup costs in conjunction with the GridFlorida original structure or in conjunction with any alternate combined transmission structures that may be required. Furthermore, the SMD NOPR presents several uncertainties, including what percentage of our investments in GridFlorida will be recovered, how the elimination of transmission charges, as proposed in the SMD NOPR, will impact us, and what amount of capital expenditures will be necessary to create a new wholesale market.

The actual structure of GridFlorida or any alternative combined transmission structure, as well as the date it may become operational, depends upon the resolution of all regulatory approvals and technical issues. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridFlorida or an alternate combined transmission structure, we cannot predict whether their creation will have any material adverse effect on our future consolidated results of operations, cash flows or financial condition.

Since weather conditions directly influence the demand for and cost of providing electricity, our results of operations, financial condition and cash flows can fluctuate on a seasonal or quarterly basis and can be negatively affected by changes in weather conditions and severe weather.

Our results of operations, financial condition, cash flows and ability to pay dividends on our common stock may be affected by changing weather conditions. Weather conditions in our service territory in Florida directly influence the demand for electricity affect the price of energy commodities necessary to provide electricity to our customers and energy commodities that our nonregulated businesses sell.

Electric power demand is generally a seasonal business. In many parts of the country, demand for power and market prices peak during the hot summer months. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the nature and location of facilities we acquire and the terms of power sale contracts into which we enter. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather could diminish our results of operations and harm our financial condition.

Furthermore, severe weather in these states, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can be destructive, causing outages, downed power lines and property damage, requiring us to incur additional and unexpected expenses and causing us to lose generating revenues. For example, during the third quarter of 2004, four hurricanes hit our service territories, resulting in storm costs of approximately $385 million. In addition, these storm costs reduced our projected 2004 regular federal income tax liability, and consequently, our ability to benefit from the tax credits generated from our synthetic fuel operations.

Our ability to recover significant costs resulting from severe weather events is subject to regulatory oversight and the timing and amount of any such recovery is uncertain and may impact our financial conditions.

During the third quarter of 2004, four hurricanes struck significant portions of our service territories, most significantly impacting PEF's territory. PEF had estimated total costs of $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

Under a regulatory order, we maintain a storm damage reserve account for major storms. With respect to storm costs in excess of the storm damage reserve account, we may seek recovery from retail ratepayers. On November 2, 2004, we filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Given that not all invoices have been received as of December 31, 2004, it is our position that the petition presents a fair projection of total cost and does not need to be updated at this time. We will update its request upon receipt and audit of all actual charges incurred. Storm reserve costs of $13 million are attributable to wholesale customers and such costs may be amortized consistent with recovery of such amounts in wholesale rates. The timing of any FPSC decision and ultimate amount recovered is uncertain at this time.

While we believe that we are legally entitled to recover these costs, if we cannot recover these costs, or costs associated with future significant weather events, in a timely manner, or in an amount sufficient to cover our actual costs, our financial conditions and results of operations could be materially and adversely impacted.

Our revenues, operating results and financial condition may fluctuate with the economy and its corresponding impact on our commercial and industrial customers as well as the demand and competitive state of the wholesale market.

Our business is impacted by fluctuations in the macroeconomy. For the year ended December 31, 2004, commercial and industrial customers represented approximately 25% and 8% of our billed electric revenues. As a result, changes in the macroeconomy can have negative impacts on our revenues. As our commercial and industrial customers experience economic hardships, our revenues can be negatively impacted.

For the year ended December 31, 2004, 8% of our billed electric revenues were from wholesale sales. Wholesale revenues fluctuate with regional demand, fuel prices, and contracted capacity. Our wholesale profitability is dependent upon our ability to renew or replace expiring wholesale contracts on favorable terms.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect our financial condition, results of operations or cash flows.

Increased competition resulting from deregulation or restructuring efforts could have a significant adverse financial impact on us and our utility subsidiaries and consequently on our results of operations and cash flows. Increased competition could also result in increased pressure to lower costs, including the cost of electricity. Retail competition and the unbundling of regulated energy and gas service could have a significant adverse financial impact on us and our subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins or

increased costs of capital. Because we have not previously operated in a competitive retail environment, we cannot predict the extent and timing of entry by additional competitors into the electric markets. Due to several factors, however, there currently is little discussion of any movement toward deregulation in Florida. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial condition, results of operations or cash flows.

Increased commodity prices may adversely affect our financial condition, results of operations or cash flows.

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 its ownership of energy-related assets. While each state commission allows electric utilities to recover certain of these costs through various cost recovery clauses, there is the potential that these future costs could be deemed imprudent by the respective commissions. There is also a delay between the timing of when these costs are incurred by the utilities and when these costs are recovered from the ratepayers, which can adversely impact our cash flows.

Risks Related to Us and Our Business

The rates that we may charge retail customers for electric power are subject to the authority of state regulators. Accordingly, our profit margins could be adversely affected if we or our utility subsidiaries do not control operating costs.

The FPSC exercises regulatory authority for review and approval of the retail electric power rates charged within Florida. State regulators may not allow our utility subsidiaries to increase retail rates in the manner or to the extent requested by those subsidiaries. The FPSC may also seek to reduce retail rates. For example, in March 2002, we entered into a Stipulation and Settlement Agreement (the "Agreement") that required us, among other things, to reduce our retail rates and to operate under a revenue sharing plan through 2005 which provides for possible rate refunds to our retail customers. The Agreement will also require increased capital expenditures for our Commitment to Excellence program. However, if our base rate earnings fall below a 10% return on equity, we may petition the FPSC to amend our base rates. As discussed below, in January 2005, we petitioned the FPSC for an increase in our retail base rates.

The cash costs we incur are generally not subject to being fixed or reduced by state regulators. We will also require dedicated capital expenditures. Thus, our ability to maintain our profit margins depends upon stable demand for electricity and our efforts to manage our costs.

If the FPSC does not approve our request for increased base rates, we will be faced with a significantly increased cost structure that will not be adequately covered by our base rates and, as a result, our results of operations, financial condition and ability to pay dividends could be materially and adversely impacted.

In January 2005, in anticipation of the expiration of the Agreement approved by the FPSC in 2002 to conclude our then-pending rate case, we notified the FPSC that we intend to request an increase in its base rates, effective January 1, 2006. In our notice, we requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. We have faced significant cost increases over the past decade and expect our operational costs to continue to increase. These costs include the costs associated with (i) completion of our Hines 3 generation facility, (ii) extraordinary hurricane damage costs, including approximately $50 million in capital costs which are not expected to be directly recoverable, (iii) our need to replenish our depleted storm reserve or adjust the annual accrual by approximately $50 million annually in light of recent history on a going-forward basis, and (iv) the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on our strong customer growth. In addition, significant additional costs include increased depreciation and fossil dismantlement expenses in excess of $70 million when the provisions of the Agreement addressing these expenses expire at the end of this year. We also face the prospect of significant compliance costs from participation in the GridFlorida regional transmission organization pursuant to FERC's transmission independence initiative and the FPSC's related directive. Finally, as is the case with most companies in our industry, we will continue to experience the pervasive upward pressure of inflation on costs in general, especially the rapidly increasing costs of employee healthcare and other benefit programs.

Under the Agreement, our base rates are at a level that existed in 1983; by contrast, the Consumer Price Index has increased just over 90 percent since then. If the FPSC does not approve our request for increased base rates, we will be faced with a significantly increased cost structure that will not be covered by our base rates. Additionally, as discussed below, our credit ratings may be negatively impacted by the outcome of the rate case. As a result, our results of operations, financial condition and ability to pay dividends to Progress Energy could be materially and adversely impacted.

There are inherent potential risks in the operation of nuclear facilities, including environmental, health, regulatory, terrorism, and financial risks that could result in fines or the shutdown of our nuclear units, which may present potential exposures in excess of our insurance coverage.

We own and operate one nuclear unit that represents approximately 838 MW, or 10%, of our generation capacity for the year ended December 31, 2004. Our nuclear facility is subject to environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, the ability to maintain adequate capital reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the costs of securing the facilities against possible terrorist attacks. We maintain a decommissioning trust and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of our insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or to shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require us to make substantial capital expenditures at our nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

From time to time, our facilities require licenses that need to be renewed or extended in order to continue operating. We do not anticipate any problems renewing these licenses as required. However, as a result of potential terrorist threats and increased public scrutiny of utilities, the licensing process could result in increased licensing or compliance costs that are difficult or impossible to predict.

Our financial performance depends on the successful operation of our electric generating facilities and our ability to deliver electricity to our customers.

Operating electric generating facilities and delivery systems involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions; and
- catastrophic events such as hurricanes, fires, earthquakes, explosions, floods, terrorist attacks or other similar occurrences.

A decrease or elimination of revenues generated from our subsidiaries' electric generating facilities and electricity delivery systems or an increase in the cost of operating the facilities could have an adverse effect on our business and results of operations.

Our business is dependent on our ability to successfully access capital markets. Our inability to access capital may limit our ability to execute our business plan, or pursue improvements and make acquisitions that we may otherwise rely on for future growth.

We rely on access to both short-term and long-term capital markets, and lines of credit with commercial banks as a significant source of liquidity for capital requirements not satisfied by the cash flow from our operations. If we are not able to access these sources of liquidity, our ability to implement our strategy will be adversely affected. We believe that we will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of our credit rating to below investment grade would increase our cost of borrowing and may adversely affect our ability to access one or more financial markets. Market disruptions create a unique uncertainty as they typically result from factors beyond our control. Such market disruptions could include:

- an economic downturn;
- the bankruptcy of an unrelated energy company;
- capital market conditions generally;
- allegations of corporate scandal at unrelated companies;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on our facilities or unrelated energy companies; or
- the overall health of the utility industry.

In addition, we believe that these market disruptions, unrelated to our business, could result in a ratings downgrade and, correspondingly, increase our cost of capital. Additional risks regarding the impact of a ratings downgrade are discussed below. Restrictions on our ability to access financial markets may affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth.

Increases in our leverage could adversely affect our competitive position, business planning and flexibility, financial condition, ability to service our debt obligations and to pay dividends on our common stock, and ability to access capital on favorable terms.

Our cash requirements arise primarily from the capital-intensive nature of our electric utilities. In addition to operating cash flows, we rely heavily on our commercial paper and long-term debt. At December 31, 2004, our commercial paper and bank borrowings and long-term debt balances were as follows (in millions):

Company	Outstanding Commercial Paper and Bank Borrowings	Total Long-Term Debt, Net
PEF	293	1,912 (a)

(a) Net of current portion, which at December 31, 2004, was $48 million.

At December 31, 2004, we had two committed credit lines that support our commercial paper programs totaling $400 million. While our financial policy precludes us from issuing commercial paper in excess of our credit lines, at December 31, 2004, we had outstanding borrowings on our credit facilities of $225 million and an outstanding commercial paper balance of $123 million, leaving an additional $52 million available for future borrowing under our credit lines.

Our credit lines impose various limitations that could impact our liquidity. Our credit facilities include defined maximum total debt to total capital (leverage) ratios and minimum coverage ratios. At December 31, 2004, the maximum and actual average leverage ratios, pursuant to the terms of the credit facilities, were 65% and 50.8%, respectively and the minimum and actual coverage ratios were 3.0 to 1 and 9.22 to 1, respectively. Under the credit facilities, indebtedness includes certain letters of credit and guarantees which are not recorded on our consolidated Balance Sheets.

In the event our capital structure changes such that we approach the permitted ratios, our access to capital and additional liquidity could decrease. Furthermore, our credit lines include provisions under which lenders could refuse to advance funds to each company under their respective credit lines in the event of a material adverse change in the respective company's financial condition. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs.

Our indebtedness also includes several cross-default provisions which could significantly impact our financial condition. Our credit lines include cross-default provisions for defaults of indebtedness in excess of $10 million. Under these provisions, if the applicable borrower or certain subsidiaries fail to pay various debt obligations in excess of $10 million, the lenders could accelerate payment of any outstanding borrowings and terminate their commitments to the credit facility. Our cross-default provisions only apply to defaults of indebtedness, but not defaults by our affiliates.

Changes in economic conditions could result in higher interest rates, which would increase our interest expense on our floating rate debt and reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- making it more difficult for us to satisfy our existing financial obligations;
- limiting our ability to obtain additional financing, if we need it, for working capital, acquisitions, debt service requirements or other purposes;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes;

- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete;
- placing us at a competitive disadvantage compared to our competitors who have less debt; and
- causing a downgrade in our credit ratings.

Any reduction in our credit ratings which would cause us to be rated below investment grade would likely increase our borrowing costs, limit our access to additional capital and require posting of collateral, all of which could materially and adversely affect our business, results of operations and financial condition.

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

In October 2004, Moody's changed its outlook for Progress Energy from stable to negative and placed the ratings of PEF under review for possible downgrade. PEC's ratings were affirmed. Accordingly, Progress Energy's senior unsecured debt is rated "Baa2," (negative outlook) by Moody's. Moody's cited weak financial ratios relative to its current ratings category, rising O&M, pension, benefit and insurance costs, and delays in executing its deleveraging plan as the primary reasons for the change in outlook. With respect to PEF, Moody's cited declining cash flows and rising leverage over the last several years, expected funding needs for large capital expenditure programs, risks regarding its upcoming 2005 rate case and the timing of hurricane cost recovery as the primary reason for placing the PEF's credit ratings under review.

In October 2004, S&P also changed Progress Energy's outlook from stable to negative. S&P cited uncertainties regarding the timing of recovery of hurricane costs, the company's debt reduction plans, and the IRS audit of our Earthco synthetic fuel facilities as the primary reasons for the change in outlook. In addition, for similar reasons, S&P reduced the short-term debt rating of Progress Energy, PEC and PEF to "A-3" from "A-2." Progress Energy's senior unsecured debt is rated "BBB-" by S&P. PEC's senior unsecured debt has been assigned a rating by S&P of "BBB" (negative outlook) and by Moody's of "Baa1" (stable outlook). PEF's senior unsecured debt has been assigned a rating by S&P of "BBB" (negative outlook) and by Moody's of "A-3" (stable outlook).

The forgoing ratings actions by S&P and Moody's do not trigger any debt or collateral guarantee requirement, however our short-term cost of capital has increased by between 25 to 87.5 basis points.

While our long-term target credit ratings are above the minimum investment grade ranking, we cannot assure you that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade could increase our borrowing costs and may adversely affect our access to capital, which could negatively impact our financial results. Further, we may be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. Although we would have access to liquidity under our committed and uncommitted credit lines, if our short-term rating were to fall below A-3 or P-2, the current ratings assigned by S&P and Moody's, respectively, our access to the commercial paper market would be significantly limited. We note that the ratings from credit agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. In the future, we could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

We could incur a significant tax liability, and our results of operations and cash flows may be materially and adversely affected if the Internal Revenue Service denies or otherwise makes unusable the Section 29 tax credits related to our coal and synthetic fuels businesses.

Solely for purposes of this Risk Factor, "we", "our", or "the Company" refer to Florida Progress Corporation

Synthetic Fuel Risks Associated With the IRS Audit

Through our Energy and Related Services segment, we produce coal-based solid synthetic fuel. The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 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. All of our synthetic fuel facilities have received favorable private letter rulings (PLRs) from the Internal Revenue Service (IRS) with respect to their synthetic fuel operations, although these PLR's do not make any "placed-in-service" determinations. These tax credits are subject to review by the IRS.

In July 2004, we were notified that the IRS field auditors anticipated taking an adverse position regarding the placed-in-service date of our four Earthco synthetic fuel facilities. Due to the auditors' position, the IRS decided to exercise its right to withdraw from the PFA program with us. In October 2004, we received the IRS field auditors' report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and that the tax credits generated by those facilities should be disallowed. We intend to contest the field auditors' findings and their proposed disallowance of the tax credits. We believe that the appeals process, including proceedings before the IRS's National Office, could take up to two years to complete. We cannot control the actual timing of resolution and cannot predict the outcome of this matter.

Through December 31, 2004, on a consolidated basis, we have used or carried forward approximately $550 million of tax credits generated by the Earthco facilities. If these credits were disallowed, our one-time exposure for cash tax payments would be $64 million (excluding interest), and earnings and equity would be reduced by approximately $550 million, excluding interest. If we were required to reverse approximately $550 million of tax credits and pay $64 million for taxes, our financial condition, results of operations and liquidity would be materially and adversely impacted.

We believe that we operate in conformity with all the necessary requirements to be allowed such credits under Section 29. The current Section 29 tax credit program will expire at the end of 2007. With respect to any IRS review or audit of our synthetic fuel operations, if we fail to prevail through the administrative or legal process, there could be a significant tax liability owed for previously taken Section 29 credits or we could lose our ability to claim future tax credits that we might otherwise be able to benefit from both of which would significantly impact earnings and cash flows.

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29 of the Internal Revenue Code. The investigation generally relates to the utilization of the tax 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. We are providing information in connection with this investigation as requested.

Synthetic Fuel Risks Associated with Pending Accounting Rules for Uncertain Tax Positions

In July 2004, the Financial Accounting Standards Board ("FASB") stated that it plans to issue an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes", that would address the accounting for uncertain tax positions. The FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. Under the prevailing sentiment, the IRS field auditors' recommendation that the Earthco tax credits be disallowed would make it difficult to conclude that the tax benefits from the Earthco facilities are probable of being sustained.. Accordingly, it is likely we would not be able to record the benefit of the Earthco tax credits on our financial statements. This could require us to create a reserve up to $550 million until the IRS issue is resolved. We cannot predict what actions the FASB will take or how any such actions might ultimately affect our financial position or results of operations, but such changes could have a material impact on our evaluation and recognition of Section 29 tax credits, which, in turn, may have a material impact on our results of operations and financial condition.

Synthetic Fuel Risks Associated With Fluctuations in the Company's Regular Income Tax Liability

The Company's synthetic fuel production levels and the amount of tax credits it can claim each year are a function of the Company's projected consolidated regular federal income tax liability. Any conditions that negatively impact the Company's tax liability, such as weather, could also diminish the Company's ability to utilize credits, including those previously generated, and the synthetic fuel is generally not economical to produce absent the credits.

Synthetic Fuel Risks Associated With Crude Oil Prices

Recent unprecedented and unanticipated increases in the price of oil could limit the amount of Section 29 tax credits or eliminate them altogether. 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 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 tax credits are eliminated for that year. For 2003, the Threshold Price was $50.14 per barrel and the Phase Out Price was $62.94 per barrel. The Threshold Price and the Phase Out Price are adjusted annually for inflation. Although data for 2004 is not yet available, we do not expect the amount of our 2004 Section 29 tax credits to be adversely affected by oil prices. We cannot predict with any certainty the Annual Average Price for 2005 or beyond. Therefore, we cannot predict whether the price of oil will have a material effect on our synthetic fuel business after 2004. However, if during 2005 through 2007, oil prices remain at historically high levels or increase, our synthetic fuel business may be adversely affected for those years and, depending on the magnitude of such increases in oil prices, the adverse affect for those years could be material and could have an impact on our synthetic fuel production plans which, in turn, may have a material impact on our results of operations and financial condition.

Our Energy and Related Services business segment is involved in natural gas drilling and production, coal terminal services, coal mining, and fuel transportation and delivery operations that are subject to risks that may reduce our revenues and adversely impact our results of operations and financial condition.

The Energy and Related Services business segment engages in businesses that have significant operational and financial risk. Operational risk includes the activities involved with natural gas drilling, coal mining, terminal and barge operations and fuel delivery. Financial risks include exposure to commodity prices, primarily fuel prices. We actively manage the operational and financial risks associated with these businesses. Nonetheless, adverse changes in fuel prices and operational issues beyond our control may result in losses in our earnings or cash flows and adversely affect our balance sheet.

SIGNATURES

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

Date: March 16, 2005

FLORIDA PROGRESS CORPORATION
(Registrant)

By: /s/ Robert B. McGehee
Robert B. McGehee
President and
Chief Executive Officer

By: /s/ Geoffrey Chatas
Geoffrey Chatas
Executive Vice President and
Chief Financial Officer

By: /s/ Robert H. Bazemore, Jr.
Robert H. Bazemore, Jr.
Controller
(Chief Accounting Officer)

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

Signature	Title	Date
/s/ Robert B. McGehee (Robert B. McGehee, Chairman)	Director	March 16, 2005
/s/ Edwin B. Borden (Edwin B. Borden)	Director	March 16, 2005
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	March 16, 2005
/s/ David L. Burner (David L. Burner)	Director	March 16, 2005
/s/ Charles W. Coker (Charles W. Coker)	Director	March 16, 2005
/s/ Richard L. Daugherty (Richard L. Daugherty)	Director	March 16, 2005

/s/ W.D. Frederick, Jr. (W.D. Frederick, Jr.)	Director	March 16, 2005
/s/ William O. McCoy (William O. McCoy)	Director	March 16, 2005
/s/ E. Marie McKee (E. Marie McKee)	Director	March 16, 2005
/s/ John H. Mullin, III (John H. Mullin, III)	Director	March 16, 2005
/s/ Richard A. Nunis (Richard A. Nunis)	Director	March 16, 2005
/s/ Peter S. Rummell (Peter S. Rummell)	Director	March 16, 2005
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	March 16, 2005
/s/ Jean Giles Wittner (Jean Giles Wittner)	Director	March 16, 2005

SIGNATURES

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

Date: March 16, 2005

FLORIDA POWER CORPORATION
(Registrant)

By: /s/ H. William Habermeyer, Jr.
H. William Habermeyer, Jr.
President and Chief Executive Officer

By: /s/ Geoffrey Chatas
Geoffrey Chatas
Executive Vice President and
Chief Financial Officer

By: /s/ Robert H. Bazemore, Jr.
Robert H. Bazemore, Jr.
Controller

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

Signature	Title	Date
s/ Robert B. McGehee Robert B. McGehee, Chairman)	Director	March 16, 2005
s/H. William Habermeyer, Jr. H. William Habermeyer, Jr.)	Director	March 16, 2005
s/Geoffrey S. Chatas Geoffrey S. Chatas)	Director	March 16, 2005
s/Fred N. Day IV Fred N. Day IV)	Director	March 16, 2005
s/ William D. Johnson William D. Johnson)	Director	March 16, 2005
s/ William S. Orser William S. Orser)	Director	March 16, 2005
s/Peter M. Scott III Peter M. Scott III)	Director	March 16, 2005

PROGRESS ENERGY FLORIDA, INC.
EXHIBIT 12
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND
PREFERRED DIVIDENDS COMBINED AND RATIO OF EARNINGS TO FIXED CHARGES

(in millions) Years Ended December 31	**2004**	2003	2002	2001	2000
Earnings, as defined:					
Net income	**$ 335**	$ 296	$ 325	$ 311	$ 212
Fixed charges, as below	**122**	103	114	117	130
Income taxes	**174**	147	163	183	151
Total earnings, as defined	**$ 631**	$ 546	$ 602	$ 611	$ 493
Fixed Charges, as defined:					
Interest on long-term debt	**$ 107**	$ 103	$ 99	$ 100	$ 102
Other interest	**10**	(6)	10	14	26
Imputed interest factor in rentals-charged principally to operating expenses	**5**	6	5	3	2
Total fixed charges, as defined	**$ 122**	$ 103	$ 114	$ 117	$ 130
Preferred dividends, as defined	**$ 2**	$ 2	$ 3	$ 3	$ 3
Total fixed charges and preferred dividends combined	**$ 124**	$ 105	$ 117	$ 120	$ 133
Ratio of earnings to fixed charges	**5.17**	5.30	5.28	5.22	3.79
Ratio of earnings to fixed charges and preferred dividends combined	**5.09**	5.20	5.15	5.09	3.71

Exhibit 23.(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 33-51573 on Form S-3, Registration Statement No. 2-93111 on Form S-3 and Registration Statement No. 333-74949 on Form S-3 of our reports dated March 7, 2005, relating to the consolidated financial statements and consolidated financial statement schedule of Florida Progress Corporation and its subsidiaries (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of a new accounting principle in 2003) appearing in this Annual Report on Form 10-K of Florida Progress Corporation for the year ended December 31, 2004.

We also consent to the incorporation by reference in Post-Effective Amendment 1 to Registration Statement No. 333-63204 on Form S-3 and Registration Statement No. 333-103974 on Form S-3 of our reports dated March 7, 2005, relating to the financial statements and financial statement schedule of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) (which report on the financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of a new accounting principle in 2003) appearing in this Annual Report on Form 10-K of PEF for the year ended December 31, 2004.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 15, 2005

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: **Provide a copy of the "Business Contracts with Officers, Directors and Affiliates" schedule included in the company's most recently filed Annual Report as required by Rule 25-6.135, Florida Administrative Code. Provide any subsequent changes** affecting the test year.

Type of data shown:

	Projected Test Year Ended	**12/31/2006**
X	**Prior Year Ended**	**12/31/2005**
X	Historical Test Year Ended	12/31/2004
	Witness:	Bazemore

Line No.	Name of Officer or Director	(A) Name and Address of Affiliated Entity	(B) Relationship With Affiliated Entity	(C) Amount of Contract or Transaction	(D) Description of Product or Service
1					
2					
3					
4					
5					
6		See attached. No changes are anticipated for 2005 and 2006.			
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					

Supporting Schedules:

Recap Schedules:

Business Contracts with Officers, Directors and Affiliates

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

List all contracts, agreements, or other business arrangements* entered into during the calendar year other than compensation-related to position with respondent) between the respondent and each officer and director listed in Part 1 of the Executive Summary. In addition, provide the same information with respect to professional services for each firm, partnership, or organization with which the officer or director is affiliated.

Note: * Business agreement, for this schedule, shall mean any oral or written business deal which binds the concerned parties for products or services during the reporting year or future years.

Name of Officer or Director	Name and Address of Affiliated Entity	Amount	Identification of Product or Service
H. William Habermeyer, Jr.	Enterprise Florida Orlando, FL	7,000	Donation
	Pinellas County Education Foundation Largo, FL	57,500	Donation
	Florida Chamber of Commerce Tallahassee, FL	35,000	Donation
	Tampa Bay Partnership Tampa, FL	1,000	Donation
	Florida Council for Economic Education Tampa, FL	15,000	Donation
	Eckerd College St. Petersburg, FL	1,000	Donation
	USF St. Petersburg Campus St. Petersburg, FL	6,000	Donation
	Boys and Girls Club of the Suncoast St. Petersburg, FL	13,100	Donation
Robert B. McGehee	INPO Atlanta, GA	720,560	Dues
	EEI Washington D.C.	27,98(	)ues
Peter M. Scott III	Capital City Club Raleigh, NC	1,437	Dues

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA, INC.

Docket No. 050078-EI

Explanation: Supply a copy of all NRC safety citations issued against the company within the last two years, a listing of corrective actions and a listing of any outstanding deficiencies. For each citation provide the dollar amount of any fines or penalties assessed against the company and account(s) each are recorded.

Type of data shown:

___	Projected Test Year Ended	12/31/2006
___	Prior Year Ended	12/31/2005
X	Historical Test Year Ended	12/31/2004
___	Witness:	Dale Young

The NRC did not issue any citations against Progress Energy Florida in 2003 and 2004.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO.: 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.		WITNESS	PAGE
1			
2			
3			
4			
5			
6	I. OVERVIEW OF FORECASTING PROCESS		
7			
8	A. Description	Myers	2
9	B. Flow Chart	Myers	3
10			
11			
12	II. DESCRIPTION OF FORECASTING METHODOLOGY		
13			
14	A. Construction Budget	Myers	4
15	B. Operating Budget	Myers	4
16	C. Balance Sheet	Myers	8
17			
18			
19	III. DESCRIPTION OF FORECASTING MODELS		
20			
21	A. Flow Chart	Crisp	13
22	B. Customers, Demand, Energy and Sales	Crisp	14
23	C. Production Costing Model	Crisp	18
24	D. Corporate Model - revenues and fuel costs	Myers	19
25			
26			
27			
28			

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO.: 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended 12/31/2005

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

I. Overview of Forecasting Process

The forecasting process employed by Progress Energy Florida to develop the projected test year data is essentially the 2005/2006 Corporate Budget.

The forecasting process for the budget is comprised of several parts: strategic and business planning, load forecasting energy dispatch planning, facilities construction planning, and the development of financial statements utilizing the corporate financial model.

Load forecasting is accomplished through an econometric modeling process which employs historic and projected input data addressing economic conditions, demographics, weather, electric price levels, and in some instances, specific customer operating plans. The output of the load forecasting process is employed in the development of system energy requirements which is a key input into the production simulation model (PROSYM).

PROSYM is used for the planning of system dispatch and simulates the use of system generation, purchased power and load control capabilities. The inputs involved are fuel and purchased power costs, system energy requirements, and plant maintenance schedules. The output of PROSYM is employed by the Financial Model to determine fuel and purchased power expense and the associated revenue.

The proposed construction expenditures reflect the facilities construction plans developed by the business units in support of their mission and serves as input into the financial model.

The operation and maintenance expenses, exclusive of fuel and purchased power, are based on the 2005/2006 budget data

The income statement is developed within the financial model using the construction expenditures, operating expense, and a number of other assumptions as input.

The balance sheet projection begins with actual balances available at the time the budget is prepared and records each known change in every significant balance sheet account. This process is done for thirteen (13) months ending on the last month of the budget period. The main source of information for the monthly balance sheet activity are the operating and construction budgets, and other assumptions input into the corporate financial model.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO.: 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:

XX Projected Test Year Ended 12/31/2006

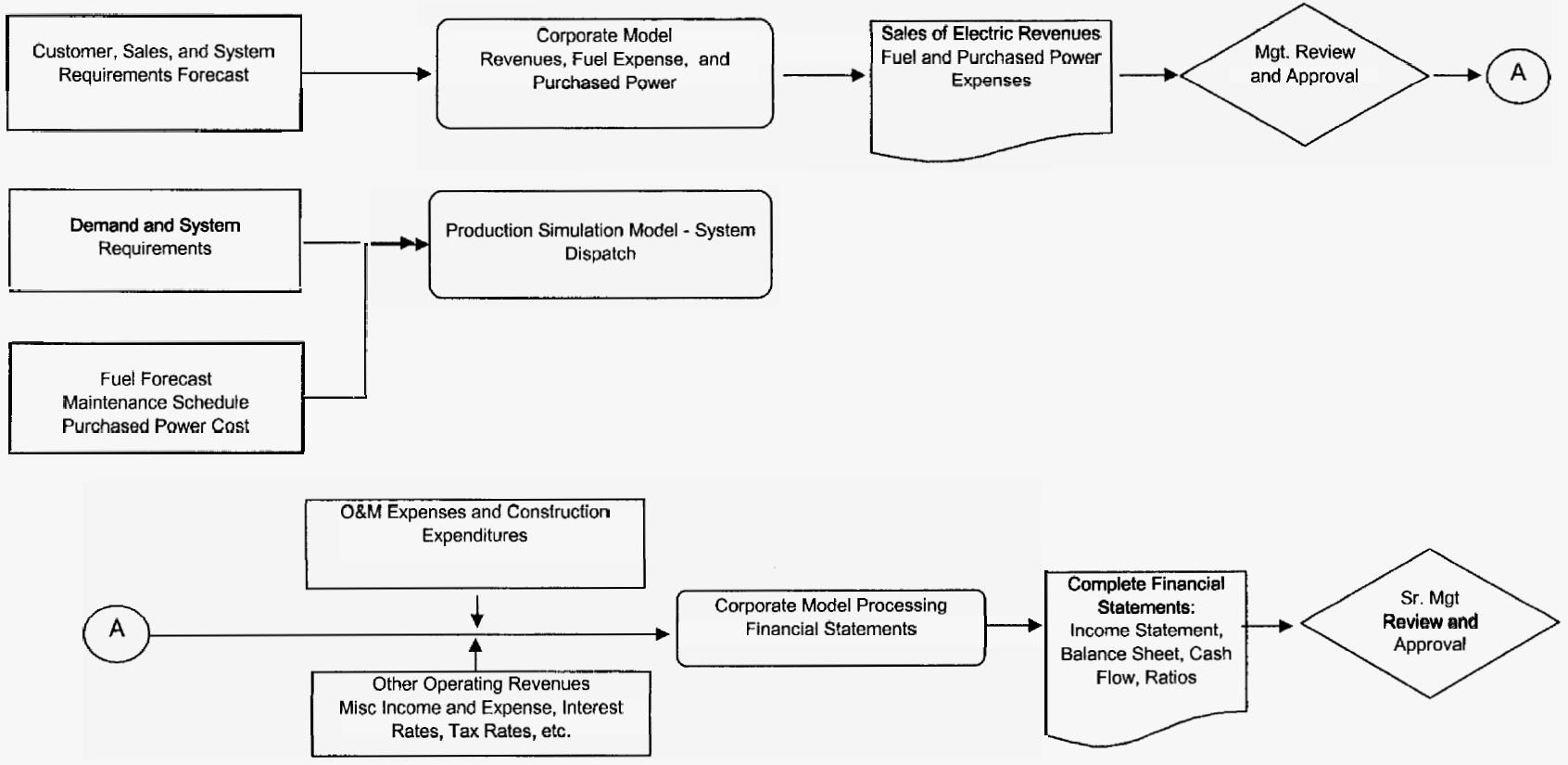
__ Prior Year Ended 12/31/2005

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

I. Overview of Forecasting Process (Cont'd)



Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology

A. Construction Budget

The process employed to define corporate construction requirements and to estimate construction costs involves the various business units and the budget development process. Thebusiness units develop their capital requirements based upon considerations such as the customers, demand and energy forecasts, safety, reliability, and economic benefit. Once they have defined their requirements, cost estimate are developed and reviewed by several levels of management. At the corporate level they are arranged in capital prioritization groups such as system growth,safety, reliability, regulatory requirements, etc. and evaluated. After they have been reviewed and approved at the corporate level the detail capital budget is developed.

B. Operating Budget

1. Operating Revenues

The 2006 base revenue projection is based on the 2006 Corporate Budget. The Budget was developed using the July 2004 sales and customer forecast by revenue and rate class and rates effective May 2002 for the rate schedules RS-1, RSL-1, LS-1, GS-1, GS-2, GSD-1, CS-1, IS-1, SL-1, SS-1, SS-2, and SS-3. There are no rate changes in this forecast. The revenue projectionmodel combines the rate by rate schedule and the sales forecast by rate schedule to determine base revenues.

Base revenues for wholesale customers are determined using the July 2004 sales, customer and demand forecast and the current rate schedule. There are no rate changes in this forecast..

Fuel Clause Revenue is developed by modeling a twelve month test period of the retail and wholesale recovery rate for 2005 & 2006 with the customer and demand forecast. The fuel revenues are based on recovery of the projected fuel expenses and calculated in the same manner as is embodied in the Commission's present procedure. Recovery is constrained by the levelized factorswhich had been established for 2005.

Energy Conservation revenue, Environmental Cost Recovery revenue, and Capacity Cost Recovery revenue is developed using the same methodology as the Fuel Clause revenue.

2. Other Operating Revenues, Exclusive of Deferred Fuel

Other Operating Revenues for 2005 & 2006 were developed by business unit staff utilizing sales forecast data and historical trends.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology (Cont'd)

3. Deferred Fuel and Capacity Revenues

The forecast of deferred fuel and capacity revenue is developed on a monthly basis using the Corporate Financial Model These revenues are determined in the Model using the same approachas is used by Accounting in developing actual deferred fuel and capacity revenues, recognizing the interaction between monthly fuel expenses and the levelized fuel adjustment factors.

4. Fuel and Purchased Power

This process begins with the preparation of a fuel forecast. The forecast includes projected prices by fuel type, transportation costs, heat value of fuels, unit size of deliveries for coal and target inventory levels and supporting economic assumptions.

The System Planning & Operations Department then uses the PROSYM program to determine fuel burn requirements for the forecast period. This simulation requires assumptions for unitcharacteristics and availabilities, purchased power availability and price, and system requirements (from the sales forecast) in addition to the fuel forecast. The PROSYM program produces burnrequirements by fuel type (physical units and BTU basis) and the price of fuels monthly for the forecast period. The price determined by PROSYM for each fuel type is a weighted average toincorporate the effect of differential fuel and transportation costs for each generation unit modeled by PROSYM.

The System Planning and Operations Department then uses the PROSYM program to determine fuel burn requirements for the forecast period. This simulation requires assumptions for unit characteristics and availabilities, purchased power availability and price, and system requirements (from the sales forecast) in addition to the fuel forecast. The PROSYM program produces burn requirements by fuel type (physical units and BTU basis) and the price of fuels monthly for the forecast period. The price determined by PROSYM for each fuel type is a weighted average to incorporate the effect of differential fuel and transportation costs for each generation unit modeled by PROSYM.

The Financial Planning Department employs the resulting PROSYM output in computing fuel expense. The initial value and quantity of inventory by fuel type is provided by Fuel Accounting. Planning personnel then simulate the physical movement of fuels through inventory for the forecast period based on initial conditions, burn requirements, purchase commitments and inventory targets. The fuel expense for each inventoried fuel is computed based on average inventory cost at the time the fuel is burned. Fuel handling expenses are projected by operations personnel based on historical experience adjusted for inflation, changes in inventory target levels, and the projected mix of fuel to be burned as determined by PROSYM.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended 12/31/2005

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology (Cont'd)

5. Fuel and Purchased Power (continued)

Assumptions for purchased power contract terms, quantities, availabilities, and prices are developed jointly by the System Planning and Operations and Term Marketing Departments. This data is used by PROSYM in determining system generation requirements as indicated above.

6. Operation and Maintenance Expenses (Exclusive of Fuel and Purchased Power)

The forecast of operation and maintenance expense exclusive of fuel and purchased power is developed from the 2006 Corporate Budget adjusted for benefits, salary and wage increase, achieved synergies, and other known changes.

7. Depreciation and Amortization

Depreciation expense is determined using forecasted 2006 monthly Electric Plant in Service. Depreciation rates were approved by the Florida Public Service Commission in Docket No.971570-E.I., Order No. PSC-98-1723-FOF-EI, December 18, 1998. Dismantlement and decommissioning accruals were suspended as part of the last rate case settlement, Docket No. 000824-EI. Amortization of intangible plant, ECCR plant, and the Sebring regulatory assets was based on currently approved rates.

8. Taxes Other Than Income Taxes

Taxes other than income taxes are forecasted by applying the estimated rate times the applicable basis for the specific item, such as real and personal property taxes, franchise fees, state gross receipts tax, regulatory commission fee, payroll taxes, etc.

9. State and Federal Income Taxes

Current income taxes are computed by applying the statutory tax rates in effect during the test year to estimated taxable income each month. Estimated taxable income is computed by adjusting the forecasted income before taxes for all permanent and timing differences between book and taxable income. Deferred income taxes are provided for all of the aforementioned timing differences.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX **Projected** Test Year Ended 12/31/2006
__ **Prior Yea**r Ended 12/31/2005
__ **Historica**l Test Year Ended
Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology (Cont'd)

10. Other Income and Deductions (Net)

Non regulated income and expenses activity, donations, and political and legislative activity is forecasted based on budgets from appropriate business units. The activity on company owned life insurance was forecasted based on assumed market conditions.

Allowance for Funds Used During Construction (AFUDC) is projected using a 7.81% cost of capital, applied to the appropriate CWIP component.

11. Interest Charges

Interest expense for Long Term Debt is determined by the series interest rate applied to the amount outstanding. There was a new issue of $350,000,000 forecasted in June of 2005. This new issue is a 3 year floating rate note, with interest rates between 2.74% and 4.10%. There are no new issues in the 2006 forecast. Interest expense on Short Term Debt is determined by applying the assumed rate of 3.40-4.40% on the average outstanding amount each month. Interest on Customer Deposits is calculated using a blended interest rate applied against the projected total customer deposit balance. Customer deposit balance is based on historical relationship between total deposits and number of customers.

12. Allowance for Funds Used During Construction

This reflects the debt portion of AFUDC. Refer to item No. 10, Other Income and Deductions (Net)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended 12/31/2005

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology (Cont'd)

C. Balance Sheet

1. Utility Plant

a. Electric Plant in Service

The month end balances for Electric Plant in Service are derived by adding plant additions expected to be closed to plant in service and subtracting expected plant retirements. The plant additions for major projects are computed using budget forecasts from the business units. Plant additions related to minor projects and blanket projects are also based on budgeted construction expenditures. Retirement estimates are based upon past historical trends.

b. Construction Work in Progress

The balance for Construction Work in Progress (CWIP) is calculated by adding monthly construction expenditures from the construction budget forecast, reduced for estimated closings to plant in service.

c. Accumulated Depreciation

The balances of Accumulated Depreciation and Amortization are derived by adding the monthly depreciation expense, (computed on the average depreciable plant in service balances), subtracting the cost of expected plant retirements. This same methodology is used for both system and 100% retail balances.

d. Net Nuclear Fuel

The month end balances for nuclear fuel are derived by adding accounts 120.1 through 120.4 less account 120.5. The accumulated provision for amortized nuclear fuel, Account 120.5, month end balance is increased by the monthly amount of fuel burned.

2. Other Property and Investments

a. Non Utility Property

Represents the change resulting from additions and depreciation on property assets utilized in the non-regulated business which are calculated in essentially the same manner as the utility plant changes described above.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology (Cont'd)

2. Other Property and Investments (cont'd)

b. Other Special Funds

Primarily the Nuclear Plant Decommissioning Fund - The funding for the decommissioning costs occurs monthly based on the last allowed level of expense authorized by the FPSC and FERC. The changes in 2006 are based on Company's study submitted as part of Docket No. 001835-EI. Income taxes are calculated on taxable funds earnings and are paid quarterly. The Company segregates the funds into Retail and Wholesale funds and qualified/non qualified. The qualified funds are funded with pre tax dollars ; the non-qualified funds with after tax dollars.

3. Current and Accrued Assets

a. Cash

Cash balance is assumed to remain unchanged for the budget year and cash needs are modeled as a change in short term debt.

b. Customer Accounts Receivable

The monthly balances for Customer Accounts Receivable was projected assuming that a specified percent of a forecasted months revenue would be received as cash that month and other amounts would be collected in subsequent **months.**

c. Materials and Supplies

It was assumed that the average material and supplies balance would be equal to the beginning balance; therefore the material and supplies are forecast at a constant level.

d. Accrued Utility Revenue

It was assumed that the accrued utility revenue balance would be equal to the beginning balance; therefore the accrued utility revenues are forecast at a constant level.

4. Deferred Debits

This account captures such items as the ECCR and ECRC current month deferral and the amortization of the prior month's deferral. In addition, it includes Sebring Rider interest accrual and the GPIF amortization. It was assumed that **the average of** the remaining deferred debits would be equal to the beginning balance; therefore they are forecast at a constant level.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology (Cont'd)

5. Other Current and Accrued Asserts

It was assumed that the other current and accrued assets balance would be equal to the beginning balance; therefore the other current and accrued assets are forecast at a constant level.

6. Capitalization

The monthly balances for common stock, preferred stock and long-term debt are developed from the Company's financing plan. The monthly balances for unappropriated retained earnings are calculated from the monthly income statement projections less expected dividends.

7. Non-current Liabilities

a. Miscellaneous Operating Reserves

This account captures such items as DOE Facility Decommissioning, Pension Liability, Deferred SERP, Medical & Life Insurance reserves, Environmental liability, End of life nuclear fuel, and last core nuclear fuel. It was assumed that the average of the remaining miscellaneous operating reservess would be equal to the beginning balance; therefore they are forecast at a constant level.

8. Current and Accrued Liabilities

a. Notes Payable

Short - term borrowing requirements as determined by the budget forecast.

b. Accounts Payable

It was assumed that the accounts payable balance would be equal to the beginning balance; therefore the accounts payable are forecast at a constant level.

c. Customer Deposits

Customer deposit balance is based on historical relationship between total deposits and number of customers. Accrued interest for the customer accounts are credited to the customers in June.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

II. Description of Forecasting Methodology (Cont'd)

8. Current and Accrued Liabilities (cont'd)

d. Taxes Accrued

The monthly balances increase by the accruals shown on the income statement and decrease by the cash payments.

e. Interest Accrued

The monthly balances increase by the accruals shown on the income statement and decrease by the cash payments.

e. Other Current Liabilities

Change reflects the loss in the Company Owned Life Insurance (COLI). The monthly balance of all other accounts in this group to remain constant for the year

9. Deferred Credits

a. Regulatory Liability - SFAS 190

This balance changes to reflect the amortization of the SFAS 190 Regulatory Liability

b. Other Deferred Credits

It was assumed that the other deferred credit balance would be equal to the beginning balance; therefore the other deferred credit are forecast at a constant level.

c. Accumulated Deferred Investment Tax Credit and Accumulated Deferred Income Taxes

The net monthly balance reflects the change on the income statement.

d. Other Deferred Liabilities

It was assumed that the other deferred liabilities balance would be equal to the beginning balance; therefore the other deferred liabilities are forecast at a constant level.

e. Asset Retirement Obligations FAS 143

The change in this balance represents the accretion expense associated with FAS 143

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

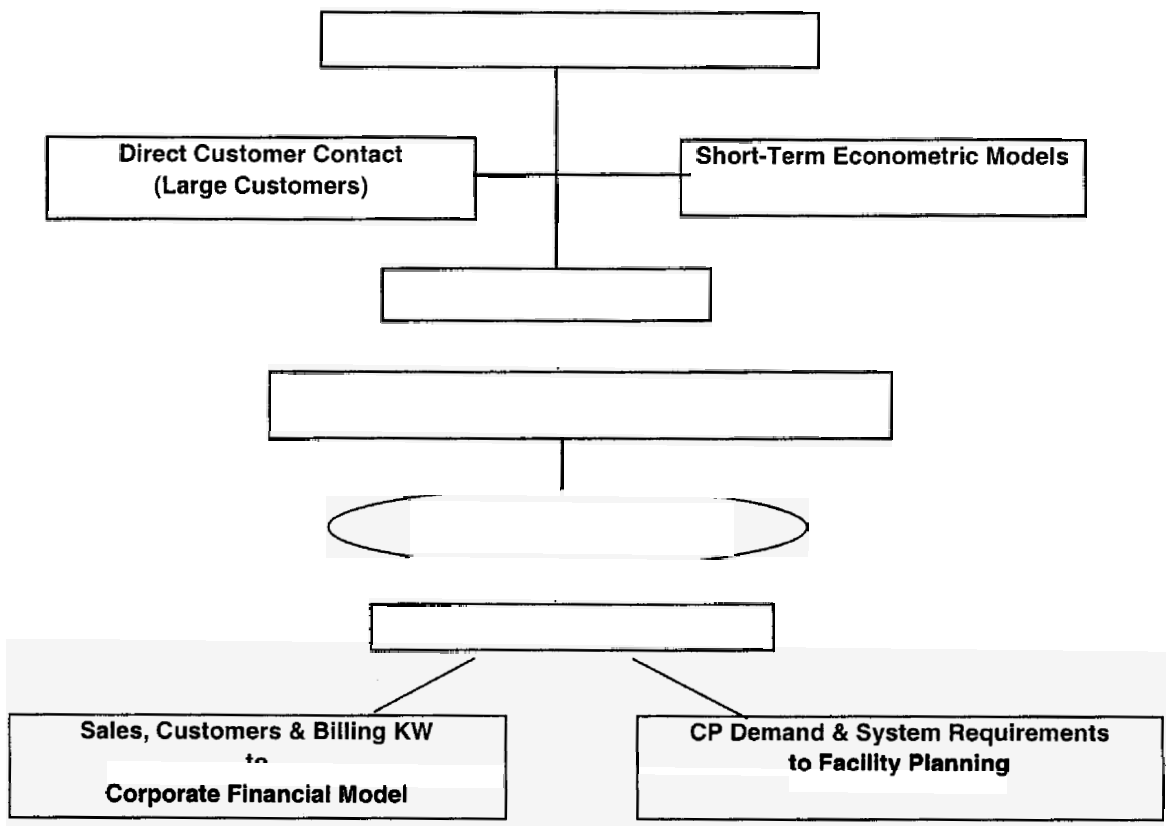
Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

III. Description of Forecasting Models

A. Flow Chart



Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

III. Description of Forecasting Models (Cont'd)

B. Customers, Energy and Demand Forecast

Energy

PEF has also developed short-term econometric models expressly designed to better capture the short-term business cycle fluctuations preceding the long-term trend path of customers' energy usage and coincident peak demand. In particular, the monthly periodicity studied in this approach better captures near-term perturbations than the end-use forecasting framework. Also, easier and more timely model updates enable the short-term econometric model to more readily incorporate the most recent projections of input variables.

SHORT-TERM ECONOMETRIC MODEL

In the short-term econometric models, energy sales in major revenue classes that have historically shown a relationship to weather and economic/demographic indicators are modeled using monthly equations. Sales are regressed against "driver" variables that best explain monthly fluctuations over a historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by independent forecasting concerns. These include the Economy.Com and the University of Florida's Bureau of Economic and Business Research. Internal company forecasts are used for projections of electric price, weather conditions and the length of the billing month. Projections of PEF's energy efficiency program impacts (conservation program reductions) and direct load control reductions are also incorporated into the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real Florida personal income, cooling degree days, heating degree days, the average number of billing days in each sales month and an intercept shift variable to account for the impact of PEF's Seasonal Service Rate. This equation captures short-term movements in customer usage. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual net new customers with PEF service area population growth. County level population projections are provided by the BEBR.

Commercial Sector

Commercial kWh use per customer is forecast based on commercial (non-agricultural, non-manufacturing and non-governmental) employment, the average number of billing days in each sales month, heating and cooling degree days, real commercial electric price and an intercept shift variable to account for the impact of the 9/11 attack influence on the Florida tourism industry. The measure of cooling degree days utilized here differs slightly from that used in the residential sector reflecting the unique behavior pattern of this class with respect to its cooling needs. Commercial customers are projected as a function of the number of residential customers served. The product of the two projections results in the commercial class energy projection.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

III. Description of Forecasting Models (Cont'd)

B. Customers, Energy and Demand Forecast (con't)

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use was consumed by the phosphate mining industry. Because this one industry dominated over a 30 percent share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted by changes in short-term economic activity. However, adequately explaining sales levels require separate explanatory variables. Non-phosphate industrial energy sales are modeled using an equation which includes the Florida Industrial Production index, the average billing days variable, HDDs and CDD, and real industrial electric price. Industrial customers have reflected no clear trend for the past several years and thus are expected to remain constant over the forecast horizon.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only five customers, the final forecast is heavily dependent upon information received from direct customer contact. PEF industrial customer representatives provide specific phosphate customer information regarding customer production schedules, area mine-out and start-up predictions, and changes in self-generation or energy supply situations over the near-term forecast horizon.

Public Authority Sector

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected using the short-term monthly econometric approach. The level of government services, and thus energy use per customer, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will impact the need for additional governmental services (i.e., schools, city services, etc.) thereby increasing SPA energy usage per customer. Monthly government employment has been determined to be the best indicator of the level of government services provided. This variable, along with heating and cooling degree days, the real price of electricity to this class and the average number of sales month billing days, result in a significant level of explained variation over the historical sample period. Intercept shift variables are also included in this model to account for the large change in school-related energy use in the billing months of January, July and August. SPA customers are projected linearly as a function of a time-trend. Again, the product of the kWh per customer projection and the customer projection results in the SPA energy projection.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

III. Description of Forecasting Models (Cont'd)

B. Customers, Energy and Demand Forecast (con't)

Demand-Side Management Programs

Each projection of every retail class-of-business MWh energy sales forecast is reduced by estimated future energy savings due to FPC-sponsored and Florida Public Service Commission (FPSC)-approved dispatchable and non-dispatchable Demand-Side Management programs. Estimated energy savings for every non-dispatchable DSM program are calculated on a program-by-program basis and aggregated for each class-of-business on the program.

Revenue Class (Class Of Business) to Rate Class Projections

The above-mentioned models project PEF revenue class (residential, commercial, industrial, street lighting and public authority) detail. This is further disaggregated to major rate class level (RS, RSLM, GS, GS-2, GSD, IS, CS, SS1, SS2, SS#, LS) using the actual 2003 historical relationships (shares) of rate class to revenue class.

Billing KW

The projection of the billing KW determinant is developed by major rate class using historical 2003 PEF billing components. Each major rate class' 2003 annual KWh and Billed KW are used to calculate a 2003 rate class load factor. This load factor, which is assumed to remain unchanged over the forecast horizon, is applied to projected monthly energy and hours in the month to result in projected monthly billed KW.

Billing Month to Calendar Month Conversion

The above-mentioned models above forecast billing month energy and customer series off of respective billing month historical series. The final forecast of energy, customers and billing kW that is uploaded to the corporate financial model is on a calendar month basis. A conversion of billing-to-calendar month level is performed using historical billed retail energy sales and retail unbilled energy. Ten years of data is studied to determine the relationship of "lagged" energy to billed energy. Lagged energy is the estimated piece of bill month energy that was generated in the prior month. This value is what was called "Unbilled energy" in the previous month. The average ratio for each month becomes the "lag factor" that is applied to the projected billed month retail energy forecast resulting in a calendar month energy figure. Once a calendar month retail forecast is developed, calendar month class energy forecasts are derived using the billing month shares of class-to-total retail relationships. For example, January residential class energy (calendar month) equals January billing month residential class energy divided by January retail billing month energy times January retail calendar month energy.

Due to the lack of data, it is assumed that billing and 'calendar month customers and billing KW are the same

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

III. Description of Forecasting Models (Cont'd)

B. Customers, Energy and Demand Forecast (con't)

Coincident Peak Demand

The PEF approach to projecting seasonal and monthly peak demand employs a disaggregation technique that separates seasonal (winter and summer) and monthly peak hour system demand into five major components. These components consist of potential firm retail load, demand-side management program capability, wholesale demand, company use demand and interruptible demand.

Potential firm retail load refers to projections of PEF retail hourly seasonal net peak demand (excluding interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of PEF's Load Management program. The historical values of this series are constructed to show the size of PEF's firm retail net peak demand had no utility-induced conservation or load control ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to retail customer levels at the time of the peak and coincident weather conditions without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data regardless of which month the peak occurred. The projections become the potential retail demand projection for the month of January (winter) and August (summer) since this is typically when the seasonal system peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected.

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been filed with the Florida Public Service Commission in the most recent DSM Goals Docket. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm retail demand.

Sales for Resale demand projections represent load supplies by PEF to other electric utilities such as Seminole Electric Cooperative, Inc., Florida Municipal Power Agency, and other electric distribution companies. The SECI supplemental demand projection is based on their forecast of their service area within the FPC control area. The level of MW to be served by PEF is dependent upon the amount of resources SECI supplies to itself or contracts with others. This amount of MW, which is sent to PEF through an annual "declaration" letter, is capable of being revised each year by amounts stated in the 1983 contract. For partial requirements customers' demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels sent via "declaration" letters. The full requirements municipal demand forecast is estimated for individual cities (Bartow, Chattahoochee, Mt Dora, Newberry, Quincy and Williston using linear models including both weather and economic variables specific to each locale. The seasonal (winter & summer) projections become the January & August peaks, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month (Nov to Mar) relative to the winter peak, and each summer month (Apr to Oct) in relation to the summer peak demand.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

III. Description of Forecasting Models (Cont'd)

PEF "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon. The interruptible and curtailable service load component is developed from historic trends, as well as the incorporation of specific information obtained from PEF's industrial service representatives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts. Since DSM program impacts represent a reduction in peak demand, they are assigned a negative value. Total system peak demand is then calculated as the arithmetic sum of these five components.

C. Production Costing Model

Progress Energy Florida utilizes the PROSYM system, a chronological production costing model leased from Global Energy Services, Inc, to project future fuel requirements and system production costs.

PROSYM differs from conventional production costing programs in its treatment of generating unit forced outages. It is these forced outages that comprise the major factor in the disruption of fuel budget forecasts, operating cost estimates, and projected utilization of high-cost peaking and mid-range equipment. Since these outages are random and unpredictable, PROSYM employs a special mathematical technique to consider their resultant impact on fuel requirements and operating costs.

Forced outages are treated within the program in a probabilistic manner. Each generating unit is represented by an up-to-six state failure model to give explicit consideration to partial loss of unit capability and outages of varying severity. Possible failure states of each unit are considered, in combination with possible failure states of all other units, in order to obtain the best possible forecast of expected fuel consumption, operation costs, and plant capacity factors.

For fuel budget applications and resource planning studies, PROSYM produces more reliable results than conventional production costing programs because of its explicit treatment of forced outages. PROSYM can be used as a generation reliability program, since the loss-of-load hours and emergency energy requirements are standard outputs. However, to determine appropriate reserve levels, tie line capacities and neighboring utility reserves must be considered. The computer model called Tie Line and Generation Reliability (TIGER) program, which assesses loss-of-load probability with or without neighboring assistance, is used.

The basic PROSYM inputs include data related to generating units, fuel characteristics, demand and energy, and system operating characteristics.

The basic PROSYM outputs are fuel costs, fuel quantities consumed, energy, and BTU requirements.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA

DOCKET NO. 050078-EI

Explanation: If a projected test year is used , provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process.

Type of data shown:
XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

III. Description of Forecasting Models (Cont'd)

D. Corporate Model

The Corporate Financial Model is used to forecast monthly and yearly financial data through the use of a number of integrated calculation modules. The model essentially consists of standard modules for Construction & Plant, Revenue, **Fuel & Purchased** Power, O&M, Finance and Income Taxes as well as processing and consolidating modules. The model was developed by Utilities International Inc.

The projection logic relies on defined relationships and input parameters to produce the financial projections. Input data include O&M expense, capital expenditures, PROSYM output, Sales Forecast of Customer and Sales, estimates **of other operating** revenues, etc. Input parameters include tax rates, depreciation rates, interest rates, cwip closing rules, composite tariff rates, etc.

The results of a study are summarized into monthly or annual financial and supporting statements or reports. The basic statements are:

1. Income Statement - This report contains the actual and projected operating revenues and expenses. In addition, debt interest, preferred stock dividends, and common stock earnings are reported on this statement.

2. Balance Sheet - This report contains the actual and projected assets and liabilities of Florida Power Corporation.

3. Cash Flow - This report summarizes the Inflow and Outflow of the Company's cash.

4. Ratios and Statistics - This report contains summaries of capital amounts of stocks and bonds, stock-bond ratios, and other data pertaining to the financial picture of the Company.

5. Electric Revenue Summary Report - This statement gives a breakdown of revenues by various classes of customers such as residential, commercial, etc as well as their individual component; fuel, energy conservation, capacity, gross receipts tax, franchise fees, regulatory assessment fees, etc.

6. Fuel Expense Report - This report provides generation and fuel expense by plant site.

In addition to the above reports, other reports are available to provide additional detail with respect to the calculated results.

Supporting Schedules: Recap Schedules:

SCHEDULE F-6 | Forecasting Models - Sensitivity of Output to Changes in Input Data | Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: If a projected test year is used - for each load, fuel cost, or sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in the outputs.

Type of data shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

Witness: Myers / Crisp

Line No.	PERCENT CHANGE IN INPUT VARIABLE	PERCENT CHANGE IN OUTPUT VARIABLE
1		
2	+10% POPULATION GROWTH	+9.78% RESIDENTIAL CUSTOMER GROWTH
3		
4	+10% FLORIDA REAL PERSONAL INCOME	+ 2.1% RESIDENTIAL AVERAGE USAGE PER CUSTOMER
5		
6	+10% FLORIDA COMMERCIAL SECTOR EMPLOYMENT	+ 4.4% COMMERCIAL SALES
7		
8	+10% FLORIDA GOVERNMENT SECTOR EMPLOYMENT	+ 3.9% PUBLIC AUTHORITY SALES
9		
10	+10% HEATING DEGREE DAYS	+ 0.7% RESIDENTIAL AVERAGE USAGE PER CUSTOMER
11		
12	+10% COOLING DEGREE DAYS	+ 2.1% RESIDENTIAL AVERAGE USAGE PER CUSTOMER
13		
14	5 DEGREE DECREASE IN 8AM WINTER DESIGN TEMPERATURE	+ 7.3% WINTER RETAIL PEAK DEMAND
15		
16	5 DEGREE INCREASE IN 6PM SUMMER DESIGN TEMPERATURE	+ 4.9% SUMMER RETAIL PEAK DEMAND
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
____Prior Year Ended ___/___/___
____Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

1 DESCRIPTION OF INPUT VARIABLES:

2	(1)	AVERAGE BILLING DAYS PER SALES MONTH
3	(2)	SERVICE AREA WEIGHTED BILLING MONTH DEGREE DAYS
4	(3)	REAL ELECTRICITY PRICES - PEF PRICE OF ELECTRICITY BY MAJOR CUSTOMER CLASS - 1982-84 CENTS/KWH
5	(4)	FLORIDA REAL TOTAL PERSONAL INCOME - IN MILLIONS OF 2000 DOLLARS
6	(5)	PERSONAL CONSUMPTION EXPENDITURES - IMPLICIT PRICE DEFLATOR - 2000=100
7	(6)	U.S. CONSUMER PRICE INDEX - ALL URBAN CONSUMERS - 1982-1984=100
8	(7)	FLORIDA SECTOR EMPLOYMENT - IN THOUSANDS
9	(8)	PEF MONTHLY NONDISPATCHABLE DSM IMPACTS BY CLASS - MWH
10	(9)	FLORIDA INDUSTRIAL PRODUCTION INDEX - 1997=100.
11	(10)	PEF SERVICE AREA POPULATION - ANNUAL
12	(11)	AVERAGE CONVENTIONAL MORTGAGE INTEREST RATE - % (ANNUAL)
13	(12)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - WINTER (JANUARY)
14	(13)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - FEBRUARY
15	(14)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - MARCH
16	(15)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - APRIL
17	(16)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - MAY
18	(17)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - JUNE
19	(18)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - JULY
20	(19)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - SUMMER (AUGUST)
21	(20)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - SEPTEMBER
22	(21)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - OCTOBER
23	(22)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - NOVEMBER
24	(23)	MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - DECEMBER
25		
26	DESCRIPTION OF OUTPUT VARIABLES:	
27	(24)	PEF BILLING MONTH ENERGY BY MAJOR CUSTOMER CLASS - MWH
28	(25)	PEF BILLING MONTH INDUSTRIAL SALES SUBSECTOR - MWH
29	(26)	PEF BILLING MONTH CUSTOMERS BY MAJOR CUSTOMER CLASS
30	(27)	PEF MONTHLY COINCIDENT PEAK - MW
31		
32		

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
____Prior Year Ended ___/___/___
____Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

Line No.	Year	Month	(1) Avg. Billing Days	(2) Service Area Weighted Degree Days			(3) Electric Cents/KWh (1982-84 $)			(4) FL Tot. Pers Income	(5) U.S. Pers. Cons Exp.	(6) U.S. CPI-U
				Res-HDD	Res-CDD	Coml-CDD	Commercial	Industrial	Pub. Auth.	(Bil of 2000 $)	IPD (2000=100)	(1982-84=100)
1	1993	1	31.85	64.7	0.0	158.4	3.809	2.921	3.561	333,786	87.0	142.60
2	1993	2	29.55	116.1	0.0	86.0	3.876	2.940	3.589	332,412	87.1	143.10
3	1993	3	29.40	139.5	0.0	43.3	3.881	2.722	3.558	334,317	87.3	143.60
4	1993	4	30.25	48.9	0.0	127.5	4.181	3.028	3.838	336,234	87.5	144.00
5	1993	5	29.95	11.3	37.0	221.8	4.154	3.054	3.850	338,161	87.7	144.20
6	1993	6	30.60	0.0	355.7	523.3	4.085	3.089	3.828	338,531	87.8	144.40
7	1993	7	30.65	0.0	739.8	741.8	4.060	3.177	3.796	338,901	87.9	144.40
8	1993	8	31.15	0.0	876.5	876.5	4.019	3.064	3.751	339,272	88.0	144.80
9	1993	9	30.30	0.0	749.1	749.1	4.007	3.073	3.774	340,450	88.1	145.10
10	1993	10	29.90	0.3	497.5	583.6	4.024	3.095	3.765	341,632	88.3	145.70
11	1993	11	30.05	31.5	130.3	326.7	4.016	3.029	3.772	342,819	88.4	145.80
12	1993	12	31.70	73.9	10.1	168.6	3.974	2.944	3.699	342,209	88.5	145.80
13	1994	1	30.65	234.5	0.0	21.4	4.056	2.923	3.729	341,600	88.7	146.20
14	1994	2	29.40	149.9	0.0	76.7	4.059	2.935	3.758	340,992	88.8	146.70
15	1994	3	29.40	52.4	0.0	134.7	4.029	2.954	3.709	342,991	89.0	147.20
16	1994	4	32.05	26.8	86.0	245.1	3.879	2.868	3.621	345,002	89.1	147.40
17	1994	5	29.55	1.0	228.1	418.6	3.946	2.959	3.673	347,025	89.3	147.50
18	1994	6	30.65	0.0	451.5	545.5	3.882	2.933	3.660	347,582	89.6	148.00
19	1994	7	30.65	0.0	707.4	712.7	3.842	2.931	3.581	348,139	89.8	148.40
20	1994	8	29.70	0.0	652.1	660.3	3.848	2.923	3.603	348,698	90.1	149.00
21	1994	9	31.85	0.0	664.6	672.3	3.795	2.865	3.525	350,600	90.2	149.40
22	1994	10	29.75	0.1	431.6	520.8	4.048	3.112	3.809	352,513	90.4	149.50
23	1994	11	30.10	2.1	94.4	363.6	4.062	3.126	3.814	354,435	90.5	149.70
24	1994	12	31.55	28.2	29.6	254.3	4.011	3.033	3.762	356,086	90.6	149.70
25	1995	1	30.50	136.6	0.0	67.8	4.048	3.019	3.772	357,744	90.8	150.30
26	1995	2	29.65	223.6	0.0	33.6	4.127	3.006	3.805	359,409	90.9	150.90
27	1995	3	29.40	86.6	0.0	98.0	4.093	3.001	3.760	360,278	91.1	151.40
28	1995	4	31.40	14.4	18.7	213.5	3.856	2.858	3.604	361,150	91.2	151.90
29	1995	5	30.20	1.1	262.7	429.1	3.861	2.925	3.659	362,023	91.4	152.20
30	1995	6	30.80	0.0	602.9	630.8	3.856	2.908	3.579	363,242	91.5	152.50

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

Line No.	Year	Month	(1) Avg. Billing Days	(2) Service Area Weighted Degree Days			(3) Electric Cents/KWh (1982-84 $)			(4) FL Tot. Pers Income	(5) U.S. Pers. Cons Exp.	(6) U.S. CPI-U
				Res-HDD	Res-CDD	Coml-CDD	Commercial	Industrial	Pub. Auth.	(Bill of 2000 $)	IPD (2000=100)	(1982-84=100)
1	1995	7	30.50	0.0	636.2	667.7	3.947	2.984	3.709	364,466	91.7	152.50
2	1995	8	29.70	0.0	729.2	729.2	3.855	2.909	3.664	365,694	91.8	152.90
3	1995	9	31.90	0.0	787.3	788.4	3.804	2.881	3.548	367,002	91.9	153.20
4	1995	10	29.70	0.2	647.2	670.5	3.873	2.883	3.636	368,315	92.1	153.70
5	1995	11	29.60	25.1	233.7	355.3	3.887	2.854	3.640	369,632	92.2	153.60
6	1995	12	30.65	90.9	10.6	99.5	3.919	2.787	3.624	371,358	92.4	153.50
7	1996	1	30.50	262.7	0.0	73.1	3.949	2.764	3.633	373,091	92.6	154.40
8	1996	2	31.05	214.7	0.0	37.5	3.894	2.758	3.617	374,833	92.8	154.90
9	1996	3	29.40	159.6	0.0	75.4	3.931	2.741	3.592	376,042	93.0	155.70
10	1996	4	30.35	95.8	0.0	118.9	3.839	2.694	3.537	377,256	93.1	156.30
11	1996	5	29.85	7.8	214.4	371.7	3.808	2.723	3.527	378,473	93.3	156.60
12	1996	6	32.20	0.1	604.9	646.5	3.733	2.726	3.474	379,627	93.4	156.70
13	1996	7	30.45	0.0	731.8	738.1	3.871	2.914	3.636	380,785	93.6	157.00
14	1996	8	31.15	0.0	802.6	802.6	3.853	2.917	3.575	381,947	93.7	157.30
15	1996	9	30.55	0.0	717.1	721.4	3.831	2.862	3.627	382,485	93.9	157.80
16	1996	10	29.65	1.2	470.4	547.0	3.888	2.900	3.607	383,024	94.1	158.30
17	1996	11	30.10	20.5	127.7	293.8	3.899	2.870	3.642	383,563	94.3	158.60
18	1996	12	31.50	72.3	13.2	111.0	3.876	2.894	3.567	385,718	94.5	158.60
19	1997	1	32.10	129.8	0.0	79.9	3.874	2.775	3.607	387,884	94.6	159.10
20	1997	2	29.50	133.7	0.0	60.7	3.944	2.783	3.597	390,063	94.8	159.60
21	1997	3	29.40	24.2	24.6	220.9	3.873	2.818	3.590	391,511	94.9	160.00
22	1997	4	30.80	5.5	7.1	247.6	3.968	2.891	3.697	392,964	94.9	160.20
23	1997	5	29.45	5.2	86.9	285.1	4.036	2.976	3.779	394,422	95.0	160.10
24	1997	6	30.75	0.2	376.3	523.9	3.961	2.875	3.718	396,122	95.1	160.30
25	1997	7	30.45	0.0	704.3	720.4	3.465	2.550	3.235	397,830	95.1	160.50
26	1997	8	29.75	0.0	754.3	754.9	3.765	2.790	3.534	399,545	95.2	160.80
27	1997	9	30.55	0.0	761.6	775.1	3.762	2.819	3.533	401,033	95.3	161.20
28	1997	10	31.05	0.3	585.0	644.7	3.730	2.770	3.506	402,527	95.4	161.60
29	1997	11	30.10	29.7	122.4	254.9	3.773	2.806	3.539	404,026	95.5	161.50
30	1997	12	31.70	97.4	11.6	134.7	3.739	2.791	3.497	407,392	95.5	161.30

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
____Prior Year Ended ___/___/___
____Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

Line No.	Year	Month	(1) Avg. Billing Days	(2) Service Area Weighted Degree Days Res-HDD	Res-CDD	Coml-CDD	(3) Electric Cents/KWh (1982-84 $) Commercial	Industrial	Pub. Auth.	(4) FL Tot. Pers Income (Bill of 2000 $)	(5) U.S. Pers. Cons Exp. IPD (2000=100)	(6) U.S. CPI-U (1982-84=100)
1	1998	1	31.90	153.2	15.6	135.4	3.736	2.699	3.494	410,785	95.6	161.60
2	1998	2	29.50	162.8	4.0	58.6	3.733	2.711	3.519	414,207	95.6	161.90
3	1998	3	29.35	130.6	5.0	68.7	3.780	2.700	3.459	416,585	95.7	162.20
4	1998	4	30.30	60.7	20.1	187.9	3.799	2.737	3.553	418,977	95.7	162.50
5	1998	5	30.05	5.7	135.0	308.1	3.799	2.755	3.582	421,383	95.8	162.80
6	1998	6	30.70	0.0	663.6	690.6	3.716	2.756	3.475	422,803	95.9	163.00
7	1998	7	29.40	0.0	849.4	849.4	3.721	2.744	3.492	424,228	96.0	163.20
8	1998	8	30.80	0.0	827.7	827.7	3.682	2.746	3.493	425,658	96.1	163.40
9	1998	9	30.25	0.0	776.4	780.4	3.686	2.740	3.485	426,185	96.2	163.60
10	1998	10	29.95	0.0	649.6	661.1	3.697	2.727	3.472	426,713	96.3	164.00
11	1998	11	30.05	5.5	197.8	349.5	3.734	2.740	3.569	427,242	96.4	164.00
12	1998	12	31.65	18.5	14.8	255.2	3.641	2.658	3.437	429,160	96.5	163.90
13	1999	1	31.95	135.3	0.0	108.7	3.631	2.633	3.382	431,086	96.6	164.30
14	1999	2	29.55	63.3	0.0	110.6	3.669	2.606	3.325	433,022	96.7	164.50
15	1999	3	29.40	119.5	0.0	37.0	3.664	2.621	3.401	433,777	96.9	165.00
16	1999	4	30.60	30.2	29.6	159.7	3.605	2.570	3.374	434,533	97.1	166.20
17	1999	5	29.60	14.2	109.2	297.5	3.656	2.640	3.410	435,291	97.3	166.20
18	1999	6	30.60	1.1	356.0	507.1	3.588	2.641	3.361	435,622	97.5	166.20
19	1999	7	30.65	0.0	651.5	653.4	3.539	2.619	3.313	435,954	97.6	166.70
20	1999	8	31.15	0.0	825.0	825.0	3.522	2.634	3.313	436,285	97.8	167.10
21	1999	9	30.30	0.0	750.7	754.7	3.510	2.603	3.323	437,085	98.0	167.90
22	1999	10	29.90	0.2	542.1	589.3	3.543	2.602	3.334	437,886	98.2	168.20
23	1999	11	30.05	14.6	176.6	315.1	3.575	2.579	3.363	438,688	98.4	168.30
24	1999	12	31.70	45.4	4.9	182.3	3.512	2.564	3.288	441,536	98.7	168.30
25	2000	1	30.65	118.0	0.0	81.6	3.526	2.534	3.277	444,403	99.0	168.80
26	2000	2	30.80	213.9	0.0	26.6	3.533	2.583	3.286	447,288	99.3	169.80
27	2000	3	29.40	40.6	0.0	92.3	3.468	2.511	3.235	449,211	99.5	171.20
28	2000	4	31.05	13.3	20.3	192.1	3.453	2.528	3.221	451,143	99.6	171.30
29	2000	5	30.55	6.0	107.4	288.8	3.485	2.609	3.297	453,083	99.8	171.50
30	2000	6	30.80	0.0	621.9	678.6	3.502	2.615	3.252	454,756	99.9	172.40

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

Line No.	Year	Month	(1) Avg. Billing Days	(2) Service Area Weighted Degree Days Res-HDD	Res-CDD	Coml-CDD	(3) Electric Cents/KWh (1982-84 $) Commercial	Industrial	Pub. Auth.	(4) FL Tot. Pers Income (Bill of 2000 $)	(5) U.S. Pers. Cons Exp. IPD (2000=100)	(6) U.S. CPI-U (1982-84=100)
1	2000	7	31.95	0.0	760.4	774.3	3.569	2.731	3.347	456,434	100.1	172.80
2	2000	8	29.65	0.0	726.7	726.7	3.593	2.797	3.410	458,119	100.2	172.80
3	2000	9	31.95	0.0	776.9	780.2	3.537	2.739	3.360	459,623	100.4	173.70
4	2000	10	29.65	5.2	452.5	514.5	3.597	2.731	3.394	461,132	100.5	174.00
5	2000	11	29.80	16.0	21.3	197.6	3.620	2.702	3.422	462,646	100.7	174.10
6	2000	12	30.60	131.0	0.0	93.0	3.592	2.728	3.370	462,883	101.0	174.00
7	2001	1	31.95	330.7	0.0	45.5	3.721	2.842	3.493	463,121	101.2	175.10
8	2001	2	29.55	186.6	0.0	64.2	3.745	2.834	3.506	463,359	101.5	175.80
9	2001	3	29.40	47.0	3.2	152.4	3.710	2.816	3.461	464,024	101.7	176.20
10	2001	4	30.05	36.9	21.7	170.5	3.898	3.060	3.665	464,691	101.9	176.90
11	2001	5	30.15	8.4	52.0	281.5	3.940	3.059	3.699	465,358	102.1	177.70
12	2001	6	30.80	0.0	448.0	549.4	3.838	3.046	3.670	466,176	102.1	178.00
13	2001	7	30.50	0.0	654.8	670.5	3.855	3.030	3.629	466,994	102.2	177.50
14	2001	8	29.70	0.0	679.0	679.0	3.861	3.147	3.661	467,814	102.2	177.50
15	2001	9	31.95	0.0	731.6	753.8	3.826	3.068	3.617	467,914	102.2	178.30
16	2001	10	29.65	0.8	353.3	470.3	3.913	3.104	3.727	468,015	102.3	177.40
17	2001	11	30.60	16.0	142.5	194.5	3.906	3.055	3.720	468,115	102.3	177.40
18	2001	12	31.30	14.1	5.8	230.6	3.817	3.025	3.592	469,992	102.4	176.70
19	2002	1	31.85	217.1	8.6	90.6	3.797	2.985	3.610	471,875	102.4	177.10
20	2002	2	29.45	96.4	0.0	120.9	3.817	2.858	3.606	473,767	102.5	177.80
21	2002	3	29.40	116.6	0.0	85.9	3.815	2.906	3.604	475,094	102.7	178.80
22	2002	4	30.80	10.0	19.4	242.5	3.740	2.941	3.506	476,425	103.0	179.80
23	2002	5	29.50	0.3	329.8	471.5	3.414	2.680	3.258	477,760	103.2	179.80
24	2002	6	29.25	0.3	494.7	572.0	3.400	2.810	3.218	477,742	103.4	179.90
25	2002	7	30.50	0.0	620.4	632.9	3.368	2.716	3.199	477,724	103.6	180.10
26	2002	8	29.70	0.0	717.8	718.2	3.360	2.638	3.217	477,706	103.8	180.70
27	2002	9	30.55	0.0	723.2	723.8	3.356	2.651	3.185	478,924	103.9	181.00
28	2002	10	29.65	0.2	667.7	683.9	3.365	2.691	3.194	480,146	104.1	181.30
29	2002	11	31.55	15.0	281.0	416.0	3.373	2.645	3.211	481,370	104.2	181.30
30	2002	12	31.75	143.8	15.6	92.1	**3.357**	**2.637**	3.175	481,507	104.4	180.90

Supporting Schedules:

G:\Rate Case\F-7r 4/15/2005 5:40 PM

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
____Prior Year Ended ___/___/___
____Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

Line No.	Year	Month	(1) Avg. Billing Days	(2) Service Area Weighted Degree Days Res-HDD	Res-CDD	Coml-CDD	(3) Electric Cents/KWh (1982-84 $) Commercial	Industrial	Pub. Auth.	(4) FL Tot. Pers Income (Bill of 2000 $)	(5) U.S. Pers. Cons Exp. IPD (2000=100)	(6) U.S. CPI-U (1982-84=100)
1	2003	1	31.85	271.7	0.0	27.1	3.360	2.602	3.168	481,643	104.7	181.70
2	2003	2	29.45	251.7	0.0	14.9	3.398	2.561	3.170	481,779	104.9	183.10
3	2003	3	29.40	41.7	30.7	193.0	3.313	2.611	3.123	483,309	105.0	184.20
4	2003	4	29.90	29.8	64.1	236.1	3.550	2.812	3.369	484,845	105.0	183.80
5	2003	5	30.40	5.3	221.8	408.1	3.553	2.859	3.381	486,385	105.1	183.50
6	2003	6	30.70	0.0	575.0	616.3	3.504	2.788	3.315	487,765	105.2	183.70
7	2003	7	30.60	0.0	706.7	706.7	3.548	2.810	3.332	489,149	105.4	183.90
8	2003	8	29.60	0.0	690.3	690.3	3.499	2.780	3.375	490,537	105.5	184.60
9	2003	9	32.05	0.0	719.3	722.9	3.430	2.774	3.232	492,246	105.6	185.20
10	2003	10	29.55	0.1	460.6	544.1	3.522	2.828	3.309	493,961	105.6	185.00
11	2003	11	28.65	2.2	167.0	370.6	3.512	2.753	3.320	495,682	105.7	184.50
12	2003	12	31.95	109.2	26.0	124.4	3.506	2.794	3.302	497,166	105.8	184.30
13	2004	1	31.65	183.0	0.0	36.4	3.860	3.028	3.690	498,655	105.9	185.20
14	2004	2	29.45	168.9	0.0	44.2	3.966	3.091	3.717	500,148	106.0	186.20
15	2004	3	29.40	96.0	0.0	99.3	3.890	3.053	3.706	501,524	106.1	187.40
16	2004	4	30.30	31.4	0.7	119.5	3.846	3.091	3.618	502,903	106.3	188.00
17	2004	5	29.90	5.6	163.7	404.0	3.854	3.388	3.711	504,287	106.4	186.69
18	2004	6	30.65	0.2	511.5	666.9	3.871	3.405	3.729	505,486	106.5	186.84
19	2004	7	30.65	0.0	754.5	827.6	3.852	3.387	3.716	506,688	106.6	186.98
20	2004	8	29.70	0.0	799.1	853.0	3.847	3.385	3.709	507,892	106.7	187.13
21	2004	9	30.30	0.0	783.9	845.3	3.863	3.397	3.719	509,096	106.9	187.30
22	2004	10	29.90	0.9	541.6	663.5	3.848	3.373	3.700	510,302	107.0	187.47
23	2004	11	30.05	16.0	158.3	388.1	3.856	3.382	3.708	511,512	107.1	187.64
24	2004	12	31.75	76.9	26.7	214.1	3.845	3.364	3.693	512,796	107.2	187.84
25	2005	1	31.75	163.6	2.1	122.3	3.609	3.127	3.461	514,083	107.4	188.04
26	2005	2	29.65	172.9	0.3	88.4	3.659	3.175	3.499	515,374	107.5	188.24
27	2005	3	29.55	102.8	8.3	137.3	3.591	3.118	3.442	516,539	107.6	188.48
28	2005	4	30.65	36.0	37.3	247.7	3.601	3.130	3.453	517,707	107.8	188.71
29	2005	5	29.40	5.6	163.7	404.0	3.570	3.115	3.431	518,877	107.9	188.95
30	2005	6	30.65	0.2	511.5	666.9	3.584	3.131	3.446	520,165	108.1	189.20

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

Line No.	Year	Month	(1) Avg. Billing Days	(2) Service Area Weighted Degree Days Res-HDD	Res-CDD	Coml-CDD	(3) Electric Cents/KWh (1982-84 $) Commercial	Industrial	Pub. Auth.	(4) FL Tot. Pers Income (Bill of 2000 $)	(5) U.S. Pers. Cons Exp. IPD (2000=100)	(6) U.S. CPI-U (1982-84=100)
1	2005	7	30.65	0.0	754.5	827.6	3.564	3.111	3.432	521,457	108.2	189.45
2	2005	8	31.10	0.0	799.1	853.0	3.557	3.107	3.424	522,752	108.4	189.71
3	**2005**	**9**	**30.45**	**0.0**	**783.9**	**845.3**	**3.571**	**3.117**	**3.431**	**524,063**	**108.5**	**189.99**
4	2005	10	29.75	0.9	541.6	663.5	3.555	3.092	3.411	525,379	108.7	190.28
5	2005	11	30.25	16.0	158.3	388.1	3.562	3.100	3.417	526,697	108.8	190.56
6	2005	12	31.65	76.9	26.7	214.1	3.548	3.081	3.400	528,195	109.0	190.88
7	2006	1	31.75	163.6	2.1	122.3	3.460	2.988	3.316	529,697	109.1	191.19
8	2006	2	29.65	172.9	0.3	88.4	3.507	3.033	3.352	531,204	109.3	191.51
9	2006	3	29.55	102.8	8.3	137.3	3.439	2.976	3.294	532,541	109.5	191.85
10	2006	4	30.65	36.0	37.3	247.7	3.447	2.986	3.303	533,882	109.7	192.19
11	2006	5	29.40	5.6	163.7	404.0	3.415	2.970	3.280	535,225	109.8	192.52
12	2006	6	30.65	0.2	511.5	666.9	3.427	2.983	3.293	536,733	110.0	192.89
13	2006	7	30.65	0.0	754.5	827.6	3.406	2.962	3.277	538,244	110.2	193.26
14	2006	8	31.10	0.0	799.1	853.0	3.397	2.957	3.268	539,760	110.4	193.64
15	2006	9	30.45	0.0	783.9	845.3	3.409	2.966	3.273	541,322	110.6	194.02
16	2006	10	29.75	0.9	541.6	663.5	3.391	2.940	3.253	542,888	110.7	194.40
17	2006	11	30.25	16.0	158.3	388.1	3.397	2.946	3.257	544,459	110.9	194.79
18	2006	12	31.65	76.9	26.7	214.1	3.382	2.927	3.240	546,067	111.1	195.16
19												
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: **For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description** of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
____Prior Year Ended __/__/__
____Historical Test Year Ended __/__/__
Witness: Myers / Crisp

Line No.	Year	Month	(7) FL Employment (000) Commercial	(7) FL Employment (000) Governmental	(8) PEF Nondispatchable DSM - MWh RES	COM	IND	SHL	SPA	(9) FL Ind. Production Index (1997=100)
1	1993	1	3,814.6	875.0	23,278	17,924	1,692	1,453	4,829	76.4
2	1993	2	3,866.6	888.3	18,610	14,784	1,537	1,146	4,084	76.6
3	1993	3	3,907.2	893.4	16,848	11,411	1,259	1,064	3,811	76.7
4	1993	4	3,933.6	895.7	14,313	10,946	1,185	942	3,584	76.8
5	1993	5	3,929.5	890.4	14,969	12,172	1,324	942	3,733	76.8
6	1993	6	3,936.3	880.2	15,840	13,564	1,515	983	3,997	77.0
7	1993	7	3,904.7	829.9	15,153	14,566	1,700	921	3,986	77.1
8	1993	8	3,914.8	817.2	16,816	17,521	2,022	1,023	4,579	77.2
9	1993	9	3,929.7	885.4	16,325	15,125	1,777	983	4,335	77.6
10	1993	10	3,955.2	906.3	14,002	13,768	1,698	880	4,102	78.0
11	1993	11	4,006.7	908.0	14,425	15,133	1,847	921	4,262	78.5
12	1993	12	4,065.8	909.7	21,356	18,926	2,061	1,228	5,264	78.9
13	1994	1	4,008.4	900.6	26,654	19,962	2,059	1,453	5,846	79.4
14	1994	2	4,056.5	913.7	21,246	16,747	1,911	1,146	5,115	79.8
15	1994	3	4,109.3	919.5	18,380	13,192	1,560	1,064	4,701	80.3
16	1994	4	4,118.5	921.2	14,888	12,637	1,553	942	4,619	80.8
17	1994	5	4,120.1	917.1	16,049	13,871	1,705	942	4,789	81.3
18	1994	6	4,127.0	907.7	17,087	15,269	1,920	983	5,075	81.8
19	1994	7	4,088.6	851.0	16,400	16,254	2,108	921	5,046	82.3
20	1994	8	4,105.3	835.1	18,072	19,377	2,466	1,023	5,736	82.8
21	1994	9	4,125.8	924.4	17,537	16,738	2,168	983	5,357	83.3
22	1994	10	4,132.8	931.2	14,702	15,296	2,060	880	5,063	83.9
23	1994	11	4,196.7	973.2	15,052	16,605	2,169	921	5,125	84.5
24	1994	12	4,265.2	932.3	23,114	20,499	2,346	1,228	6,093	85.0
25	1995	1	4,192.7	917.2	29,117	21,467	2,304	1,453	6,592	85.5
26	1995	2	4,245.3	932.5	23,195	18,258	2,200	1,146	5,929	86.0
27	1995	3	4,295.1	939.8	19,638	14,603	1,802	1,064	5,398	86.2
28	1995	4	4,266.3	936.3	15,525	14,114	1,940	942	5,598	86.3
29	1995	5	4,278.8	935.4	16,974	15,434	2,150	942	5,863	86.5
30	1995	6	4,290.0	921.6	18,129	16,921	2,437	983	6,254	86.9

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

Line No.	Year	Month	(7) FL Employment (000) Commercial	(7) FL Employment (000) Governmental	(8) PEF Nondispatchable DSM - MWh RES	COM	IND	SHL	SPA	(9) FL Ind. Production Index (1997=100)
1	1995	7	4,236.9	856.2	17,442	17,965	2,671	921	6,274	87.2
2	1995	8	4,262.1	841.4	19,161	21,334	3,123	1,023	7,153	87.6
3	1995	9	4,284.7	931.0	18,601	18,532	2,799	983	6,679	88.0
4	1995	10	4,301.8	932.4	15,397	17,083	2,688	880	6,358	88.4
5	1995	11	4,378.6	937.7	15,710	18,367	2,765	921	6,308	88.8
6	1995	12	4,442.7	938.7	24,730	22,373	2,904	1,228	7,226	89.0
7	1996	1	4,332.3	927.5	31,380	23,298	2,822	1,453	7,625	89.2
8	1996	2	4,386.0	940.4	25,006	20,236	2,811	1,146	6,994	89.4
9	1996	3	4,440.3	970.2	20,857	16,509	2,347	1,064	6,189	90.0
10	1996	4	4,412.0	941.7	16,216	16,187	2,643	942	6,699	90.7
11	1996	5	4,427.1	940.1	17,915	17,642	2,902	942	6,947	91.3
12	1996	6	4,429.3	924.8	19,267	19,327	3,282	983	7,319	91.8
13	1996	7	4,399.7	858.3	18,683	20,551	3,589	921	7,264	92.4
14	1996	8	4,429.9	849.5	20,459	24,129	4,142	1,023	8,132	92.9
15	1996	9	4,448.4	938.4	19,785	21,216	3,754	983	7,482	93.4
16	1996	10	4,464.0	944.9	16,201	19,793	3,649	880	7,044	93.9
17	1996	11	4,534.7	952.3	16,693	20,982	3,782	921	6,869	94.5
18	1996	12	4,600.7	952.4	26,772	25,846	4,046	1,228	7,804	95.3
19	1997	1	4,521.4	947.7	33,893	27,250	4,057	1,453	8,192	96.1
20	1997	2	4,567.4	954.8	26,945	23,324	3,878	1,146	7,449	96.9
21	1997	3	4,620.6	956.4	22,155	19,014	3,282	1,064	6,567	97.5
22	1997	4	4,625.0	955.0	17,032	18,393	3,310	942	7,014	98.1
23	1997	5	4,637.2	956.0	18,995	19,724	3,509	942	7,242	98.7
24	1997	6	4,641.3	943.2	20,712	21,374	3,884	983	7,609	99.4
25	1997	7	4,613.2	877.4	20,343	22,499	4,167	921	7,541	100.2
26	1997	8	4,639.7	867.9	22,146	25,876	4,669	1,023	8,381	100.9
27	1997	9	4,671.0	951.1	21,236	22,657	4,156	983	7,684	101.7
28	1997	10	4,680.6	962.0	17,180	20,977	3,965	880	7,209	102.5
29	1997	11	4,735.9	965.5	17,959	21,892	4,019	921	6,995	103.4
30	1997	12	4,800.7	969.2	29,333	26,969	4,248	1,228	7,950	103.8

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

Line			(7) FL Employment (000)		(8) PEF Nondispatchable DSM - MWh					(9) FL Ind. Production
No.	Year	Month	Commercial	Governmental	RES	COM	IND	SHL	SPA	Index (1997=100)
1	1998	1	4,738.7	964.6	36,972	28,265	4,186	1,453	8,321	104.2
2	1998	2	4,787.6	969.5	29,256	24,200	3,987	1,146	7,559	104.7
3	1998	3	4,828.8	974.0	23,667	19,758	3,375	1,064	6,660	105.1
4	1998	4	4,811.3	967.2	18,007	19,167	3,407	942	7,111	105.5
5	1998	5	4,818.1	967.9	20,238	20,638	3,623	942	7,356	105.9
6	1998	6	4,837.3	952.6	22,365	22,461	4,020	983	7,745	106.4
7	1998	7	4,804.2	890.0	22,208	23,744	4,322	921	7,697	106.8
8	1998	8	4,822.1	873.5	24,014	27,214	4,836	1,023	8,548	107.3
9	1998	9	4,838.2	963.5	22,820	23,999	4,324	983	7,852	107.8
10	1998	10	4,884.4	973.5	18,229	22,335	4,134	880	7,379	108.3
11	1998	11	4,944.5	978.6	19,335	23,218	4,185	921	7,161	108.9
12	1998	12	5,008.7	982.7	32,048	29,029	4,505	1,228	8,208	109.3
13	1999	1	4,903.9	965.7	40,003	28,785	4,275	1,453	8,321	109.8
14	1999	2	4,963.8	978.0	31,632	24,627	4,069	1,146	7,559	110.3
15	1999	3	5,008.7	981.8	25,523	20,107	3,444	1,064	6,660	110.8
16	1999	4	4,996.8	980.2	19,381	19,505	3,476	942	7,111	111.3
17	1999	5	5,001.8	979.4	21,806	21,001	3,697	942	7,356	111.8
18	1999	6	5,025.7	964.1	24,142	22,857	4,101	983	7,745	112.3
19	1999	7	4,967.8	895.6	24,007	24,162	4,410	921	7,697	112.9
20	1999	8	4,990.5	881.5	25,936	27,690	4,934	1,023	8,548	113.5
21	1999	9	4,998.0	973.2	24,616	24,420	4,412	983	7,852	114.2
22	1999	10	5,032.1	988.5	19,620	22,728	4,218	880	7,379	114.9
23	1999	11	5,103.8	996.8	20,848	23,624	4,270	921	7,161	115.6
24	1999	12	5,175.0	1,002.5	34,645	29,540	4,599	1,228	8,208	116.2
25	2000	1	5,087.2	991.6	42,816	29,383	4,300	1,453	8,321	116.9
26	2000	2	5,132.1	1,001.5	33,837	25,136	4,093	1,146	7,559	117.5
27	2000	3	5,195.1	1,009.7	27,246	20,523	3,464	1,064	6,660	118.5
28	2000	4	5,180.9	1,014.6	20,657	19,909	3,496	942	7,111	119.5
29	2000	5	5,190.1	1,034.1	23,262	21,435	3,719	942	7,356	120.4
30	**2000**	**6**	**5,216.6**	**948.3**	**25,791**	**23,330**	**4,125**	983	7,745	120.5

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

Line No.	Year	Month	(7) FL Employment (000) Commercial	(7) FL Employment (000) Governmental	(8) PEF Nondispatchable DSM - MWh RES	COM	IND	SHL	SPA	(9) FL Ind. Production Index (1997=100)
1	2000	7	5,169.8	932.7	25,677	24,663	4,436	921	7,697	120.6
2	2000	8	5,199.6	1,005.7	27,719	28,259	4,963	1,023	8,548	120.7
3	2000	9	5,224.8	1,009.9	26,283	24,924	4,437	983	7,852	120.6
4	2000	10	5,236.2	1,018.2	20,910	23,198	4,242	880	7,379	120.6
5	2000	11	5,305.8	1,025.4	22,252	24,109	4,294	921	7,161	120.6
6	2000	12	5,364.8	1,029.1	37,056	30,150	4,626	1,228	8,208	119.9
7	2001	1	5,227.8	1,014.7	45,517	29,722	4,326	1,453	8,321	119.2
8	2001	2	5,283.2	1,028.2	35,956	25,425	4,117	1,146	7,559	118.6
9	2001	3	5,336.1	1,034.3	28,900	20,759	3,484	1,064	6,660	118.0
10	2001	4	5,307.7	1,035.2	21,883	20,137	3,517	942	7,111	117.5
11	2001	5	5,309.1	1,036.6	24,660	21,682	3,740	942	7,356	116.9
12	2001	6	5,309.4	968.8	27,376	23,598	4,149	983	7,745	116.4
13	2001	7	5,244.2	952.9	27,281	24,946	4,461	921	7,697	115.8
14	2001	8	5,262.1	1,033.2	29,432	28,581	4,991	1,023	8,548	115.2
15	2001	9	5,259.8	1,039.2	27,884	25,209	4,463	983	7,852	115.0
16	2001	10	5,250.2	1,041.7	22,150	23,465	4,267	880	7,379	114.8
17	2001	11	5,293.1	1,047.8	23,600	24,384	4,319	921	7,161	114.6
18	2001	12	5,333.1	1,049.2	39,372	30,496	4,653	1,228	8,208	114.7
19	2002	1	5,228.2	1,033.9	48,539	30,049	4,353	1,453	8,321	114.8
20	2002	2	5,272.7	1,044.2	38,324	25,704	4,142	1,146	7,559	114.9
21	2002	3	**5,326.5**	1,048.8	30,750	20,987	3,505	1,064	6,660	115.3
22	2002	4	**5,310.7**	1,049.3	23,253	20,359	3,538	942	7,111	115.7
23	2002	5	**5,315.6**	1,053.7	26,223	21,919	3,763	942	7,356	116.1
24	2002	6	**5,308.0**	977.9	29,147	23,856	4,174	983	7,745	116.2
25	2002	7	**5,251.2**	964.0	29,074	25,220	4,488	921	7,697	116.4
26	2002	8	**5,266.5**	1,048.2	31,348	28,892	5,021	1,023	8,548	116.6
27	2002	9	**5,269.5**	1,056.6	29,675	25,485	4,489	983	7,852	116.5
28	2002	10	**5,290.2**	1,062.0	23,537	23,722	4,292	880	7,379	116.3
29	2002	11	**5,353.3**	1,064.8	25,108	24,649	4,344	921	7,161	116.2
30	2002	12	5,407.1	1,067.5	41,962	30,831	4,681	1,228	8,208	116.4

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended __/__/__

____Historical Test Year Ended __/__/__

Witness: Myers / Crisp

Line No.	Year	Month	(7) FL Employment (000) Commercial	(7) FL Employment (000) Governmental	(8) PEF Nondispatchable DSM - MWh RES	COM	IND	SHL	SPA	(9) FL Ind. Production Index (1997=100)
1	2003	1	5,302.2	1,052.7	51,569	30,440	4,379	1,453	8,321	116.6
2	2003	2	5,343.5	1,063.5	40,700	26,037	4,167	1,146	7,559	116.7
3	2003	3	5,392.1	1,067.1	32,606	21,259	3,526	1,064	6,660	116.4
4	2003	4	5,380.5	1,065.2	24,628	20,622	3,558	942	7,111	116.0
5	2003	5	5,383.4	1,072.6	27,791	22,203	3,785	942	7,356	115.7
6	2003	6	5,379.5	994.6	30,924	24,165	4,198	983	7,745	116.1
7	2003	7	5,350.0	981.3	30,874	25,547	4,514	921	7,697	116.4
8	2003	8	5,371.2	1,063.1	33,269	29,263	5,050	1,023	8,548	116.8
9	2003	9	5,384.0	1,069.7	31,471	25,814	4,516	983	7,852	117.5
10	2003	10	5,403.3	1,075.7	24,927	24,029	4,317	880	7,379	118.1
11	2003	11	5,459.9	1,080.1	26,621	24,966	4,370	921	7,161	118.7
12	2003	12	5,506.2	1,080.5	44,559	31,229	4,709	1,228	8,208	119.4
13	2004	1	5,414.4	1,064.4	54,204	30,610	4,406	1,453	8,321	120.1
14	2004	2	5,456.5	1,077.6	42,766	26,182	4,192	1,146	7,559	120.7
15	2004	3	5,498.1	1,082.3	34,220	21,378	3,547	1,064	6,660	121.4
16	2004	4	5,479.8	1,078.8	25,823	20,737	3,579	942	7,111	122.0
17	2004	5	5,491.5	1,079.4	29,154	22,326	3,807	942	7,356	122.7
18	2004	6	5,505.3	1,080.0	32,470	24,300	4,223	983	7,745	123.2
19	2004	7	5,519.2	1,080.6	32,438	25,689	4,540	921	7,697	123.8
20	2004	8	5,533.1	1,081.2	34,940	29,425	5,079	1,023	8,548	124.4
21	2004	9	5,549.0	1,081.7	33,033	25,957	4,542	983	7,852	124.8
22	2004	10	5,565.0	1,082.2	26,136	24,163	4,342	880	7,379	125.3
23	2004	11	5,581.0	1,082.7	27,937	25,104	4,395	921	7,161	125.7
24	2004	12	5,598.3	1,083.3	46,818	31,403	4,737	1,228	8,208	126.2
25	2005	1	5,615.7	1,083.8	56,971	30,680	4,432	1,453	8,321	126.6
26	2005	2	5,633.1	1,084.3	44,936	26,242	4,216	1,146	7,559	127.0
27	2005	3	5,651.1	1,084.9	35,914	21,426	3,568	1,064	6,660	127.3
28	2005	4	5,669.1	1,085.5	27,078	20,785	3,600	942	7,111	127.6
29	2005	5	5,687.2	1,086.1	30,586	22,377	3,829	942	7,356	127.9
30	2005	6	5,704.3	1,086.8	34,092	24,355	4,247	983	7,745	128.2

Supporting Schedules:

G:\Rate Case\F-7r 4/15/2005 5:40 PM

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

Line No.	Year	Month	(7) FL Employment (000) Commercial	(7) FL Employment (000) Governmental	(8) PEF Nondispatchable DSM - MWh RES	COM	IND	SHL	SPA	(9) FL Ind. Production Index (1997=100)
1	2005	7	5,721.4	1,087.4	34,081	25,748	4,567	921	7,697	128.5
2	2005	8	5,738.6	1,088.0	36,695	29,491	5,109	1,023	8,548	128.8
3	2005	9	5,756.9	1,088.8	34,673	26,016	4,568	983	7,852	129.0
4	2005	10	5,775.3	1,089.6	27,406	24,218	4,367	880	7,379	129.3
5	2005	11	5,793.7	1,090.3	29,318	25,160	4,420	921	7,161	129.6
6	2005	12	5,810.9	1,091.2	49,190	31,474	4,765	1,228	8,208	129.9
7	2006	1	5,828.1	1,092.1	59,738	30,850	4,459	1,453	8,321	130.2
8	2006	2	5,845.5	1,093.0	47,105	26,387	4,241	1,146	7,559	130.5
9	2006	3	5,861.2	1,094.0	37,609	21,545	3,588	1,064	6,660	130.8
10	2006	4	5,876.9	1,095.0	28,334	20,899	3,621	942	7,111	131.1
11	2006	5	5,892.7	1,096.0	32,018	22,501	3,851	942	7,356	131.5
12	2006	6	5,907.5	1,097.1	35,715	24,490	4,272	983	7,745	131.8
13	2006	7	5,922.3	1,098.2	35,723	25,890	4,593	921	7,697	132.2
14	2006	8	5,937.1	1,099.3	38,449	29,653	5,138	1,023	8,548	132.6
15	2006	9	5,951.3	1,100.4	36,313	26,160	4,594	983	7,852	132.9
16	2006	10	5,965.4	1,101.5	28,676	24,352	4,392	880	7,379	133.3
17	2006	11	5,979.6	1,102.6	30,699	25,298	4,446	921	7,161	133.6
18	2006	12	5,993.4	1,103.6	51,562	31,648	4,793	1,228	8,208	134.0
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										

Supporting Schedules:

G:\Rate Case\F-7r 4/15/2005 5:40 PM

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

Line No.	Year	(10) PEF Service Area Population	(11) Conventional Mortgage Interest Rate (%)
1			
2	1984	3,455,803	12.48
3	1985	3,583,736	11.71
4	1986	3,704,212	10.26
5	1987	3,824,876	9.30
6	1988	3,937,374	9.29
7	1989	4,058,226	10.12
8	1990	4,163,028	10.04
9	1991	4,268,010	9.31
10	1992	4,346,125	8.13
11	1993	4,432,988	7.17
12	1994	4,521,584	7.47
13	1995	4,617,980	7.85
14	1996	4,704,102	7.72
15	1997	4,801,846	7.69
16	1998	4,894,503	7.10
17	1999	5,012,899	7.28
18	2000	5,152,262	7.95
19	2001	5,278,067	7.03
20	2002	5,397,003	6.54
21	2003	5,531,162	5.75
22	2004	5,651,167	5.91
23	2005	5,762,000	6.42
24	2006	5,871,744	7.21
25			
26			
27			
28			
29			
30			

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

(12) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - WINTER (JANUARY)

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 2 Hr	Temp@Peak 24 Hr
1	01/15/75 08:00	3,002	0	**0**	**0**	**0**	**185**	**2,331**	**622,729**	**622,729**	40.90	45.44
2	01/19/76 08:00	3,511	140	0	0	0	305	2,724	642,370	642,370	35.85	40.04
3	01/19/77 11:00	3,875	220	250	0	0	254	3,415	667,012	667,012	30.25	38.32
4	02/07/78 09:00	4,125	0	0	0	0	155	3,276	699,885	699,885	36.50	43.66
5	01/04/79 08:00	4,224	30	0	0	0	167	3,327	728,064	728,064	38.80	39.30
6	03/03/80 09:00	4,419	290	141	0	0	311	3,709	769,947	769,947	34.35	37.33
7	01/13/81 09:00	5,088	250	0	0	11	290	4,127	796,461	796,461	31.23	34.85
8	01/12/82 08:00	5,347	0	0	10	12	139	4,213	824,522	824,522	28.35	34.81
9	01/14/83 08:00	4,701	76	0	22	36	149	3,691	853,487	853,487	40.40	46.32
10	12/27/83 09:00	4,913	206	0	39	36	168	4,021	879,822	879,822	40.03	37.41
11	01/22/85 09:00	5,813	272	0	60	42	177	5,289	928,445	928,445	27.00	31.75
12	01/28/86 08:00	5,977	253	0	75	51	146	5,443	968,355	968,355	27.48	40.48
13	02/10/87 08:00	5,087	200	0	85	58	167	4,744	1,015,858	1,015,858	40.68	46.99
14	01/28/88 08:00	6,188	0	0	90	61	183	5,430	1,049,378	1,049,378	38.20	44.84
15	02/24/89 08:00	6,137	493	0	96	66	202	5,931	1,092,496	1,092,496	36.38	42.07
16	12/23/89 18:00	6,817	614	0	99	66	230	6,384	1,118,486	1,118,486	31.18	38.97
17	02/16/91 09:00	6,056	0	0	103	66	163	5,288	1,157,960	1,157,960	34.75	48.89
18	01/17/92 08:00	6,982	0	0	115	66	181	6,010	1,175,043	1,175,043	36.80	44.59
19	03/15/93 07:00	6,219	107	675	124	66	155	6,185	1,204,634	1,204,634	37.55	42.90
20	02/03/94 08:00	6,955	7	0	157	66	199	6,014	1,237,906	1,237,906	39.33	45.87
21	02/09/95 08:00	7,722	1,120	0	176	66	281	7,657	1,262,674	1,262,674	31.08	41.74
22	02/05/96 08:00	8,807	1,482	0	201	72	255	8,822	1,284,588	1,284,588	27.15	36.34
23	01/19/97 08:00	8,066	111	0	238	72	290	6,963	1,306,626	1,306,626	33.93	39.08
24	03/13/98 08:00	6,885	516	0	241	75	351	6,426	1,330,183	1,330,183	42.85	46.02
25	01/06/99 08:00	8,936	1,149	0	313	75	334	8,400	1,348,608	1,345,608	33.45	38.31
26	01/27/00 08:00	9,303	395	0	348	75	326	8,067	1,378,860	1,371,076	35.43	41.60
27	01/05/01 08:00	9,839	1,162	0	374	75	248	9,219	1,417,453	1,410,390	31.20	40.08
28	01/09/02 08:00	9,721	376	105	399	75	294	8,757	1,446,162	1,437,323	31.63	41.04
29	01/24/03 08:00	10,507	536	0	437	75	263	9,754	1,477,251	1,468,022	27.53	43.83
30	01/29/04 08:00	8,748	0	0	421	75	315	7,391	1,512,696	1,502,612	40.25	48.03
31	Jan-05								1,541,365	1,536,193	35.80	41.40
32	Jan-06								1,569,867	1,564,599	35.80	41.40

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

(13) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - FEBRUARY

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 2 Hr	Temp@Peak 24 Hr
1	02/02/80 09:00	4,391	0	0	0	0	0	3,720	767,305	767,305	40.85	41.48
2	02/04/81 08:00	4,610	0	0	0	11	0	3,754	800,402	800,402	36.78	42.17
3	02/23/82 08:00	3,374	0	0	11	12	0	2,781	827,913	827,913	50.00	58.10
4	02/09/83 08:00	4,554	0	0	23	36	0	3,806	858,177	858,177	41.35	48.83
5	02/07/84 08:00	4,711	0	0	43	36	0	4,165	894,287	894,287	38.65	45.77
6	02/13/85 08:00	4,516	0	0	61	42	186	4,027	933,728	933,728	44.13	49.66
7	02/14/86 08:00	4,651	0	0	76	51	182	4,081	974,409	974,409	43.18	45.94
8	02/10/87 08:00	5,087	200	0	85	58	167	4,741	1,015,858	1,015,858	40.68	46.99
9	02/07/88 09:00	5,385	0	0	90	61	242	4,492	1,055,127	1,055,127	43.68	43.76
10	02/24/89 08:00	6,137	493	0	96	66	202	6,007	1,092,496	1,092,496	36.38	42.07
11	02/26/90 08:00	4,345	0	0	66	51	193	3,923	1,130,677	1,130,677	51.23	55.41
12	02/16/91 09:00	6,056	0	0	103	66	163	5,288	1,157,960	1,157,960	34.75	48.89
13	02/09/92 09:00	5,390	0	0	114	66	165	4,790	1,179,614	1,179,614	46.60	51.98
14	02/19/93 08:00	6,134	11	0	130	66	230	5,312	1,202,501	1,202,501	36.73	51.46
15	02/03/94 08:00	6,955	7	0	157	66	199	6,014	1,237,906	1,237,906	39.33	45.87
16	02/09/95 08:00	7,722	1,120	0	176	66	281	7,657	1,262,674	1,262,674	31.08	41.74
17	02/05/96 08:00	8,807	1,482	0	201	72	255	8,822	1,284,588	1,284,588	27.15	36.34
18	02/08/97 08:00	5,794	497	0	230	72	346	5,554	1,310,073	1,310,073	47.35	52.92
19	02/10/98 08:00	6,156	504	0	269	75	344	5,919	1,328,366	1,328,366	46.20	52.07
20	02/23/99 08:00	7,470	0	0	302	75	347	6,407	1,354,441	1,352,041	43.38	46.94
21	02/06/00 09:00	5,508	0	0	335	75	293	5,024	1,384,909	1,381,190	45.23	47.32
22	02/06/01 08:00	7,735	0	0	362	75	320	6,598	1,422,826	1,417,737	38.95	51.49
23	02/28/02 08:00	8,941	0	0	384	75	310	7,681	1,453,892	1,447,358	35.70	44.77
24	02/08/03 08:00	6,508	0	0	421	75	251	6,108	1,482,847	1,478,137	47.10	55.50
25	02/19/04 08:00	7,791	0	0	450	75	271	7,146	1,516,880	1,510,474	43.28	50.34
26	February-05								1,546,560	1,538,910	41.40	47.00
27	February-06								1,575,067	1,567,277	41.40	47.00
28												
29												
30												
31												

Supporting Schedules:

Recap Schedules

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

(14) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - MARCH

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	Firm Retail MW w/Co Use Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 2 Hr	Temp@Peak 24 Hr
1	03/03/80 09:00	4,419	290	141	0	0	311	3,751	769,947	769,947	34.35	37.33
2	03/24/81 08:00	3,157	0	0	0	11	0	2,571	802,385	802,385	50.83	56.66
3	03/08/82 08:00	3,491	0	0	12	12	0	2,882	830,185	830,185	44.13	56.95
4	03/11/83 09:00	3,942	0	0	25	36	0	3,360	860,314	860,314	46.58	54.82
5	03/01/84 08:00	4,493	0	0	44	36	0	4,034	895,566	895,566	39.75	47.34
6	03/19/85 08:00	3,399	0	0	63	42	148	3,049	937,528	937,528	49.65	55.67
7	03/02/86 09:00	4,268	0	0	76	51	177	3,801	977,420	977,420	44.45	45.75
8	3/31/1987 20:00	3,671	0	0	85	58	287	3,330	1,019,317	1,019,317	51.73	57.88
9	03/16/88 08:00	5,000	0	0	91	61	218	4,272	1,057,892	1,057,892	44.55	49.36
10	3/9/1989 20:00	5,009	50	0	96	66	251	4,585	1,096,101	1,096,101	47.18	46.64
11	3/16/1990 17:00	3,806	0	0	101	66	317	3,442	1,133,830	1,133,830	84.75	76.00
12	03/11/91 08:00	5,157	0	0	104	66	202	4,508	1,160,366	1,160,366	47.98	53.80
13	03/09/92 09:00	4,653	176	0	112	66	209	4,372	1,181,203	1,181,203	48.95	51.71
14	03/15/93 07:00	6,219	107	675	124	66	155	6,184	1,204,634	1,204,634	37.55	42.90
15	3/28/94 17:00	5,159	0	0	144	66	271	4,665	1,240,598	1,240,598	83.43	79.69
16	03/10/95 08:00	5,064	0	0	161	66	300	4,464	1,257,584	1,257,584	48.63	53.89
17	03/09/96 09:00	7,246	0	0	184	72	325	6,270	1,285,785	1,285,785	36.48	44.75
18	3/5/1997 17:00	5,028	0	0	208	72	344	4,753	1,312,256	1,312,256	82.85	74.63
19	03/13/98 08:00	6,885	516	0	241	75	351	6,426	1,330,183	1,330,183	42.85	46.02
20	03/05/99 08:00	6,320	0	0	274	75	344	5,432	1,356,798	1,354,398	47.88	53.06
21	3/31/00 17:00	5,922	0	0	306	75	332	5,356	1,388,403	1,384,703	82.48	77.43
22	03/08/01 08:00	6,271	0	0	333	75	318	5,391	1,425,503	1,420,289	49.05	54.95
23	03/05/02 08:00	8,345	0	0	348	75	343	7,288	1,454,792	1,449,199	37.75	45.03
24	3/20/03 15:00	7,178	0	0	381	75	326	6,576	1,486,108	1,480,365	86.98	78.93
25	March-04								1,519,650	1,513,902	45.93	51.25
26	March-05								1,549,414	1,542,226	45.93	51.25
27	March-06								1,577,932	1,570,612	45.93	51.25
28												
29												
30												

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

(15) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - APRIL

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	04/03/80 19:00	2,701	0	0	0	0	0	2,267	767,025	767,025	82.70
2	04/30/81 18:00	2,863	0	0	0	11	0	2,335	796,788	796,788	87.10
3	04/21/82 18:00	3,261	0	0	9	12	0	2,752	826,328	826,328	88.80
4	04/07/83 20:00	2,982	0	0	20	36	0	2,493	855,763	855,763	83.20
5	04/30/84 18:00	2,941	0	0	36	36	0	2,745	893,627	893,627	87.80
6	04/26/85 19:00	3,059	0	0	50	42	186	2,702	934,788	934,788	86.10
7	04/30/86 18:00	3,232	0	0	62	51	230	2,810	973,366	973,366	86.80
8	04/01/87 08:00	4,174	0	0	69	58	288	3,747	1,015,991	1,015,991	44.80
9	04/27/88 18:00	3,876	0	0	74	61	269	3,286	1,052,559	1,052,559	84.90
10	04/28/89 18:00	4,089	0	0	79	66	291	3,800	1,094,290	1,094,290	86.00
11	04/30/90 20:00	4,451	-36	0	83	66	249	4,066	1,128,936	1,128,936	86.30
12	04/30/91 17:00	5,268	18	0	86	66	195	4,770	1,153,245	1,153,245	88.50
13	04/24/92 17:00	4,479	0	0	90	66	241	4,002	1,173,663	1,173,663	84.10
14	04/23/93 08:00	3,924	0	0	99	66	252	3,506	1,206,553	1,206,553	53.50
15	04/15/94 17:00	5,288	0	0	114	66	267	4,721	1,231,169	1,231,169	86.50
16	04/20/95 18:00	5,487	0	0	130	66	257	4,948	1,255,838	1,255,838	86.20
17	04/29/96 18:00	5,614	0	0	153	72	307	5,158	1,278,712	1,278,712	88.70
18	04/27/97 18:00	5,085	0	0	171	72	304	4,727	1,300,877	1,300,877	86.70
19	04/02/98 17:00	5,630	0	0	195	75	359	5,175	1,322,735	1,322,735	83.90
20	04/27/99 20:00	6,659	97	0	214	75	342	5,952	1,351,102	1,344,202	85.60
21	04/03/00 18:00	5,923	0	0	229	75	292	5,311	1,384,482	1,377,437	82.40
22	04/13/01 17:00	7,157	0	0	244	75	303	6,106	1,420,664	1,412,504	86.90
23	04/22/02 17:00	7,208	0	0	251	75	287	6,579	1,448,974	1,440,688	86.90
24	04/07/03 18:00	7,209	0	0	268	75	234	6,589	1,485,905	1,477,262	85.60
25	April-04								1,520,211	1,509,848	85.60
26	April-05								1,548,804	1,537,949	85.60
27	April-06								1,577,331	1,566,278	85.60
28											
29											

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

___Prior Year Ended ___/___/___

___Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

(16) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - MAY

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	05/19/80 18:00	3,377	0	0	0	0	0	2,761	759,674	759,674	88.40
2	05/18/81 18:00	3,265	0	0	0	11	0	2,649	789,235	789,235	92.20
3	05/28/82 18:00	3,401	0	0	10	12	0	2,849	815,602	815,602	90.70
4	05/24/83 17:00	3,622	0	0	21	36	0	3,054	844,583	844,583	90.00
5	05/07/84 18:00	3,708	0	0	37	36	0	3,405	883,429	883,429	91.30
6	05/31/85 17:00	3,914	0	0	51	42	171	3,543	923,669	923,669	93.10
7	05/29/86 18:00	4,020	0	0	62	51	190	3,721	961,035	961,035	90.00
8	05/21/87 17:00	3,865	0	0	69	58	211	3,562	1,001,596	1,001,596	85.50
9	05/23/88 18:00	4,418	0	0	75	61	296	3,723	1,039,770	1,039,770	89.90
10	05/26/89 17:00	5,112	0	0	79	66	273	4,674	1,081,575	1,081,575	92.00
11	05/16/90 17:00	5,304	0	0	83	66	279	4,727	1,114,508	1,114,508	90.10
12	05/29/91 17:00	5,395	113	0	87	66	228	4,827	1,138,449	1,138,449	88.40
13	05/31/92 18:00	4,892	0	0	94	66	163	4,365	1,159,029	1,159,029	88.40
14	05/18/93 18:00	5,030	0	0	107	66	229	4,522	1,192,483	1,192,483	85.40
15	05/16/94 16:00	6,054	0	0	127	66	251	5,327	1,215,282	1,215,282	88.60
16	05/17/95 17:00	6,851	0	0	147	66	308	5,961	1,227,948	1,227,948	90.70
17	05/23/96 18:00	6,360	0	0	173	72	326	5,661	1,262,357	1,262,357	90.10
18	05/27/97 17:00	6,798	0	0	192	72	340	6,055	1,286,438	1,286,438	89.70
19	05/21/98 17:00	7,066	146	0	220	75	348	6,394	1,311,442	1,311,442	88.40
20	05/25/99 18:00	7,236	0	0	239	75	348	6,289	1,342,512	1,325,512	87.90
21	05/26/00 17:00	8,166	38	0	254	75	301	7,022	1,377,602	1,360,381	93.20
22	05/30/01 18:00	7,752	0	0	269	75	316	6,936	1,413,924	1,393,739	89.00
23	05/03/02 17:00	8,127	0	0	281	75	358	7,101	1,447,989	1,427,079	90.80
24	05/12/03 17:00	8,037	0	0	300	75	276	7,409	1,484,110	1,462,177	88.10
25	May-04								1,517,146	1,492,340	89.30
26	May-05								1,546,600	1,521,314	89.30
27	May-06								1,575,139	1,549,390	89.30
28											
29											

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

(17) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - JUNE

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	06/17/80 18:00	3,632	0	0	0	0	0	3,009	757,617	757,617	92.00
2	06/16/81 18:00	4,355	0	0	0	11	208	3,338	786,120	786,120	96.80
3	06/09/82 18:00	4,017	0	0	11	12	0	3,364	812,049	812,049	91.70
4	06/28/83 18:00	3,764	0	0	23	36	0	3,191	841,947	841,947	89.30
5	06/21/84 18:00	3,908	0	0	38	36	0	3,583	880,583	880,583	92.70
6	06/05/85 17:00	4,548	127	0	53	42	194	4,164	921,014	921,014	94.30
7	06/27/86 17:00	4,084	0	0	63	51	198	3,752	957,814	957,814	89.10
8	06/24/87 16:00	4,701	0	0	70	58	233	4,251	1,001,215	1,001,215	91.30
9	06/29/88 17:00	4,945	0	0	75	61	256	4,192	1,037,071	1,037,071	90.20
10	06/15/89 18:00	5,525	0	0	79	66	213	4,990	1,078,483	1,078,483	90.70
11	06/20/90 19:00	5,946	-52	0	84	66	198	5,214	1,111,342	1,111,342	90.80
12	06/28/91 17:00	5,820	0	0	87	66	211	5,075	1,134,054	1,134,054	91.10
13	06/22/92 18:00	5,929	-2	0	95	66	171	5,237	1,155,460	1,155,460	89.60
14	06/08/93 17:00	6,438	0	0	111	66	244	5,568	1,188,220	1,188,220	91.90
15	06/27/94 18:00	6,681	0	0	133	66	262	5,830	1,211,705	1,211,705	91.00
16	06/09/95 17:00	6,814	0	0	157	66	247	5,976	1,233,825	1,233,825	90.20
17	06/25/96 15:00	6,768	0	0	185	72	306	5,999	1,258,492	1,258,492	91.60
18	06/19/97 17:00	6,964	0	0	205	72	322	6,275	1,283,644	1,283,644	90.60
19	06/19/98 15:00	8,110	37	0	235	75	346	6,961	1,309,761	1,309,761	93.40
20	06/15/99 17:00	7,575	0	0	253	75	345	6,613	1,339,809	1,324,809	88.60
21	06/05/00 17:00	8,154	0	0	268	75	282	7,051	1,377,795	1,353,821	92.40
22	06/13/01 18:00	8,269	0	0	283	75	316	7,303	1,414,582	1,387,064	90.80
23	06/13/02 17:00	8,076	0	0	296	75	294	7,402	1,448,142	1,416,567	88.60
24	06/11/03 17:00	8,287	0	0	317	75	246	7,685	1,484,918	1,452,902	89.80
25	June-04								1,517,762	1,481,836	91.40
26	June-05								1,546,977	1,510,364	91.40
27	June-06								1,575,534	1,538,249	91.40
28											
29											
30											
31											
32											

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

(18) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - JULY

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	07/09/80 18:00	3,952	0	0	0	0	0	3,203	757,341	757,341	93.20
2	07/14/81 17:00	4,219	0	0	0	11	0	3,484	787,671	787,671	95.70
3	07/01/82 18:00	3,834	0	0	12	12	0	3,204	814,460	814,460	92.20
4	07/18/83 17:00	4,520	0	0	24	36	0	3,779	843,601	843,601	96.00
5	07/09/84 16:00	3,983	0	0	39	36	0	3,644	882,774	882,774	91.60
6	07/10/85 18:00	4,273	0	0	54	42	157	3,889	922,718	922,718	93.40
7	07/31/86 17:00	4,565	0	0	64	51	173	4,161	959,491	959,491	91.00
8	07/24/87 17:00	4,897	0	0	70	58	247	4,372	1,001,588	1,001,588	91.70
9	07/12/88 18:00	5,309	0	0	75	61	199	4,525	1,038,466	1,038,466	93.00
10	07/10/89 19:00	5,592	61	0	80	66	262	5,015	1,079,364	1,079,364	93.10
11	07/31/90 17:00	5,790	0	0	84	66	249	5,055	1,112,297	1,112,297	92.00
12	07/22/91 18:00	5,903	0	0	88	66	177	5,202	1,134,186	1,134,186	91.30
13	07/07/92 17:00	6,357	0	0	97	66	150	5,556	1,156,554	1,156,554	90.90
14	07/28/93 18:00	6,545	0	0	115	66	269	5,585	1,188,277	1,188,277	90.00
15	07/11/94 17:00	6,495	0	0	136	66	254	5,700	1,211,709	1,211,709	89.50
16	07/05/95 16:00	6,840	0	0	161	66	239	6,044	1,235,360	1,235,360	90.10
17	07/22/96 18:00	7,164	45	0	189	72	309	6,337	1,260,953	1,260,953	91.50
18	07/03/97 17:00	7,462	44	0	209	72	273	6,642	1,273,304	1,273,304	93.80
19	07/02/98 16:00	8,004	49	0	239	75	352	7,074	1,311,815	1,311,815	94.70
20	07/27/99 17:00	8,186	0	0	258	75	342	6,950	1,341,841	1,320,841	92.40
21	07/12/00 18:00	8,360	171	0	272	75	225	7,395	1,381,199	1,355,127	91.10
22	07/30/01 18:00	8,163	0	0	287	75	218	7,286	1,417,136	1,387,953	90.30
23	07/17/02 17:00	9,034	0	0	302	75	309	7,899	1,449,480	1,416,724	94.00
24	07/09/03 15:00	8,476	0	0	324	75	256	7,732	1,487,636	1,453,443	90.30
25	July-04								1,520,304	1,476,975	92.10
26	July-05								1,549,313	1,505,161	92.10
27	July-06								1,577,885	1,532,924	92.10
28											
29											
30											
31											
32											

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

___Prior Year Ended ___/___/___

___Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

(19) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - SUMMER (AUGUST)

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	08/02/80 18:00	3,995	40	0	0	0	258	2,685	759,485	759,485	89.50
2	06/16/81 18:00	4,355	0	0	0	11	208	3,338	786,120	786,120	96.80
3	09/13/82 17:00	4,086	0	0	13	12	173	3,231	816,846	816,846	91.40
4	08/22/83 18:00	4,610	0	0	28	36	163	3,698	845,671	845,671	93.90
5	08/09/84 18:00	4,163	72	0	40	36	201	3,611	885,873	885,873	93.00
6	06/05/85 17:00	4,548	127	0	53	42	194	4,164	921,014	921,014	94.30
7	08/01/86 17:00	4,644	0	0	64	51	133	4,289	962,171	962,171	92.40
8	08/26/87 18:00	5,196	1	0	70	58	225	4,636	1,005,106	1,005,106	91.70
9	07/12/88 18:00	5,309	0	0	75	61	199	4,525	1,038,466	1,038,466	93.00
10	08/07/89 18:00	5,832	0	0	80	66	240	5,216	1,082,169	1,082,169	92.30
11	06/20/90 19:00	5,946	-52	0	84	66	198	5,214	1,111,342	1,111,342	90.80
12	08/08/91 17:00	5,925	0	0	89	66	192	5,213	1,134,944	1,134,944	90.90
13	07/07/92 17:00	6,357	0	0	97	66	150	5,556	1,156,554	1,156,554	90.90
14	08/05/93 17:00	6,729	0	0	118	66	272	5,807	1,190,103	1,190,103	92.20
15	06/27/94 18:00	6,681	0	0	133	66	262	5,830	1,211,705	1,211,705	91.00
16	08/15/95 15:00	7,128	160	0	170	66	269	6,295	1,243,197	1,243,197	93.20
17	07/22/96 18:00	7,164	45	0	189	72	261	6,385	1,260,953	1,260,953	91.50
18	07/03/97 17:00	7,462	44	0	209	72	307	6,608	1,273,304	1,273,304	93.80
19	07/02/98 16:00	8,004	49	0	239	75	352	7,074	1,311,815	1,311,815	94.70
20	08/30/99 18:00	8,358	156	0	267	75	344	7,188	1,346,537	1,324,842	91.20
21	08/08/00 18:00	8,500	54	0	280	75	286	7,306	1,383,339	1,356,450	91.60
22	08/29/01 17:00	8,471	0	0	295	75	286	7,438	1,418,421	1,388,668	90.00
23	07/17/02 17:00	9,034	0	0	302	75	309	7,899	1,449,480	1,416,724	94.00
24	7/9/2003 15:00	8,476	0	0	324	75	256	7,732	1,487,636	1,453,443	90.30
25	August-04								1,522,829	1,476,873	92.20
26	August-05								1,551,666	1,504,844	92.20
27	August-06								1,580,258	1,532,578	92.20
28											
29											
30											
31											
32											

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

(20) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - SEPTEMBER

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	09/08/80 18:00	3,716	0	0	0	0	150	2,924	763,228	763,228	90.00
2	09/02/81 18:00	3,854	0	0	0	11	150	3,003	792,382	792,382	90.90
3	09/13/82 17:00	4,086	0	0	13	12	173	3,231	816,846	816,846	91.40
4	09/06/83 18:00	4,379	0	0	26	36	185	3,472	849,167	849,167	93.90
5	09/14/84 17:00	4,091	0	0	42	36	120	3,608	890,368	890,368	91.60
6	09/09/85 18:00	4,257	0	0	56	42	99	3,934	928,916	928,916	91.00
7	09/30/86 18:00	4,428	0	0	65	51	193	4,085	967,267	967,267	88.30
8	09/09/87 18:00	5,016	0	0	71	58	265	4,507	1,008,413	1,008,413	90.80
9	09/22/88 18:00	5,224	0	0	76	61	250	4,417	1,045,171	1,045,171	90.50
10	09/15/89 17:00	5,483	0	0	80	66	232	4,948	1,086,309	1,086,309	88.20
11	09/13/90 18:00	5,614	60	0	85	66	196	5,080	1,116,702	1,116,702	92.20
12	09/19/91 17:00	5,815	44	0	89	66	241	5,136	1,137,537	1,137,537	90.50
13	09/22/92 17:00	5,927	0	0	99	66	212	5,215	1,161,287	1,161,287	89.30
14	09/22/93 18:00	6,173	0	0	119	66	209	5,411	1,192,998	1,192,998	90.00
15	09/02/94 17:00	6,323	0	0	139	66	255	5,551	1,215,676	1,215,676	88.70
16	09/14/95 17:00	6,654	0	0	167	66	252	5,933	1,242,035	1,242,035	89.90
17	09/03/96 17:00	7,052	0	0	193	72	341	6,266	1,262,297	1,262,297	90.60
18	09/16/97 17:00	6,932	0	0	210	72	336	6,140	1,284,073	1,284,073	90.60
19	09/01/98 16:00	7,312	0	0	240	75	353	6,485	1,314,817	1,314,817	90.90
20	09/04/99 18:00	7,604	0	0	258	75	342	6,567	1,348,739	1,326,834	93.00
21	09/14/00 18:00	8,014	0	0	271	75	277	6,890	1,388,320	1,362,028	88.80
22	09/04/00 17:00	7,930	0	0	286	75	309	7,120	1,421,915	1,393,628	87.40
23	09/18/02 17:00	8,362	0	0	302	75	257	7,503	1,456,054	1,424,284	89.50
24	09/24/03 17:00	7,982	0	0	324	75	268	7,406	1,492,463	1,458,083	89.00
25	September-04								1,524,614	1,488,557	90.40
26	September-05								1,553,311	1,516,579	90.40
27	September-06								1,581,924	1,544,520	90.40
28											
29											
30											
31											
32											

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/___/___

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

(21) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - OCTOBER

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	10/02/80 18:00	3,033	0	0	0	0	0	2,578	769,047	769,047	85.90
2	10/01/81 18:00	3,325	0	0	0	11	0	2,762	797,529	797,529	87.40
3	10/11/82 17:00	3,452	0	0	14	12	0	2,874	822,037	822,037	85.80
4	10/06/83 18:00	3,557	0	0	28	36	0	3,048	855,515	855,515	88.70
5	10/29/84 19:00	3,329	0	0	43	36	0	3,095	896,163	896,163	83.30
6	10/03/85 17:00	4,037	0	0	57	42	130	3,698	934,278	934,278	90.50
7	10/01/86 18:00	4,432	0	0	66	51	193	4,120	973,683	973,683	88.20
8	10/01/87 18:00	3,561	0	0	72	58	219	3,283	1,014,711	1,014,711	83.50
9	10/01/88 18:00	4,398	0	0	76	61	262	3,679	1,052,972	1,052,972	88.60
10	10/16/89 20:00	4,964	-200	0	81	66	258	4,371	1,093,226	1,093,226	85.30
11	10/04/90 17:00	5,221	0	0	85	66	196	4,725	1,122,641	1,122,641	87.40
12	10/05/91 15:00	4,736	0	0	88	66	221	4,266	1,143,385	1,143,385	87.00
13	10/09/92 18:00	4,599	98	0	95	66	200	4,317	1,166,725	1,166,725	84.30
14	10/21/93 17:00	5,403	0	0	111	66	216	4,899	1,199,172	1,199,172	87.10
15	10/03/94 17:00	5,482	0	0	127	66	194	5,000	1,222,715	1,222,715	85.60
16	10/02/95 17:00	6,108	0	0	151	66	293	5,476	1,247,438	1,247,438	88.20
17	10/01/96 17:00	5,508	0	0	173	72	299	4,853	1,270,667	1,270,667	82.90
18	10/01/97 17:00	6,426	0	0	188	72	341	5,784	1,289,534	1,289,534	88.80
19	10/07/98 17:00	7,034	0	0	215	75	348	6,262	1,319,948	1,319,948	88.60
20	10/11/99 17:00	6,845	0	0	232	75	343	5,919	1,353,167	1,331,734	85.20
21	10/05/00 18:00	7,699	0	0	245	75	252	6,677	1,392,136	1,366,408	87.50
22	10/06/01 16:00	6,909	0	0	260	75	238	6,051	1,424,851	1,396,020	85.50
23	10/07/02 17:00	7,920	0	0	272	75	256	7,021	1,458,077	1,428,624	87.90
24	10/13/03 17:00	7,383	0	0	292	75	283	6,937	1,495,956	1,462,649	86.80
25	October-04								1,527,799	1,491,663	86.90
26	October-05								1,556,391	1,519,582	86.90
27	October-06								1,585,027	1,547,545	86.90
28											
29											
30											
31											
32											

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
____Prior Year Ended ___/___/___
____Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

(22) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - NOVEMBER

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 5 Hr Avg
1	11/29/80 09:00	3,084	0	0	0	0	0	2,631	780,650	780,650	47.40
2	11/23/81 08:00	3,842	0	0	0	11	0	3,151	809,889	809,889	44.70
3	11/03/82 19:00	3,031	0	0	20	12	0	2,523	835,898	835,898	80.00
4	11/18/83 08:00	3,645	0	0	38	36	0	3,042	868,408	868,408	46.20
5	11/14/84 08:00	3,561	0	0	57	36	121	3,089	909,564	909,564	49.10
6	11/13/85 19:00	3,154	0	0	72	42	170	2,861	947,069	947,069	81.00
7	11/12/86 19:00	3,521	0	0	83	51	252	3,230	988,125	988,125	79.80
8	11/13/87 08:00	3,496	0	0	89	58	218	3,218	1,028,941	1,028,941	52.30
9	11/17/88 19:00	3,685	0	0	94	61	278	3,143	1,066,684	1,066,684	81.00
10	11/06/89 19:00	3,886	0	0	99	66	302	3,622	1,108,006	1,108,006	80.60
11	11/28/90 19:00	3,988	0	0	104	66	248	3,700	1,136,374	1,136,374	79.00
12	11/26/91 08:00	5,178	333	0	106	66	58	4,902	1,156,604	1,156,604	45.10
13	11/30/92 08:00	5,229	0	0	112	66	212	4,575	1,181,109	1,181,109	45.30
14	11/01/93 08:00	4,979	0	0	126	66	188	4,405	1,206,113	1,206,113	40.40
15	11/09/94 19:00	4,825	0	0	140	66	274	4,438	1,238,015	1,238,015	80.10
16	11/16/95 08:00	5,553	0	0	160	66	323	4,825	1,261,880	1,261,880	47.90
17	11/01/96 16:00	5,190	0	0	183	72	394	4,757	1,276,748	1,276,748	82.80
18	11/17/97 08:00	5,239	0	0	202	72	331	4,642	1,304,054	1,304,054	45.30
19	11/19/98 19:00	5,387	0	0	231	75	348	5,059	1,328,672	1,328,672	79.90
20	11/01/99 17:00	5,735	0	0	262	75	334	5,098	1,363,154	1,346,333	76.10
21	11/22/00 08:00	7,605	0	0	286	75	297	6,252	1,401,421	1,380,859	41.70
22	11/01/01 19:00	5,386	0	0	314	75	335	5,071	1,433,643	1,411,411	78.00
23	11/11/02 15:00	6,978	0	0	336	75	329	6,259	1,465,126	1,443,000	84.80
24	11/05/03 14:00	6,887	0	0	369	75	317	6,471	1,502,214	1,477,505	82.70
25	November-04								1,533,728	1,506,432	80.90
26	November-05								1,562,258	1,534,456	80.90
27	November-06								1,590,919	1,562,610	80.90
28											
29											
30											
31											
32											

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended __/__/__

____Historical Test Year Ended __/__/__

Witness: Myers / Crisp

(23) MONTHLY RETAIL COINCIDENT PEAK DEMAND INPUTS - DECEMBER

Line No.	Date	Recorded Peak	Direct Load Control	Firm Retail Not Served	Nondispatchable DSM	SS COGEN	TOTAL IS/CS	w/Co Use Firm Retail MW Pre DSM	R,C,& I Customer Forecast	R,C, & I Customers Adj. for EDB & SSR	Temp@Peak 2 Hr	Temp@Peak 24 Hr
1	12/28/80 10:00	3,804	0	0	0	0	0	3,136	789,985	789,985	41.88	46.69
2	12/20/81 09:00	4,515	0	0	0	11	0	3,653	818,746	818,746	35.10	36.99
3	12/18/82 09:00	3,849	0	0	21	12	0	3,194	846,656	846,656	45.08	49.12
4	12/27/83 09:00	4,913	206	0	39	36	168	4,169	879,822	879,822	40.03	37.41
5	12/08/84 09:00	4,254	0	0	59	36	148	3,617	921,134	921,134	44.28	45.86
6	12/26/85 09:00	5,206	0	0	74	42	88	4,698	959,937	959,937	31.35	43.51
7	12/10/86 19:00	3,203	0	0	83	51	275	2,867	1,000,724	1,000,724	76.45	73.43
8	12/18/87 08:00	4,938	0	0	90	58	235	4,378	1,039,206	1,039,206	44.78	47.68
9	12/19/88 08:00	5,614	195	0	95	61	229	4,834	1,078,645	1,078,645	38.78	43.53
10	12/23/89 18:00	6,817	574	0	99	66	230	6,451	1,118,486	1,118,486	31.18	38.97
11	12/11/90 08:00	5,017	0	0	104	66	174	4,403	1,146,685	1,146,685	43.75	53.36
12	12/05/91 08:00	5,351	312	0	111	66	193	4,915	1,167,674	1,167,674	41.95	48.99
13	12/03/92 08:00	5,160	0	0	122	66	182	4,489	1,190,969	1,190,969	48.83	56.59
14	12/27/93 08:00	6,653	0	0	146	66	189	5,671	1,225,652	1,225,652	39.85	45.21
15	12/05/94 19:00	4,487	0	0	164	66	277	4,062	1,249,845	1,249,845	71.95	72.53
16	12/25/95 09:00	6,977	0	0	187	66	209	5,954	1,269,541	1,269,541	38.55	41.80
17	12/20/96 19:00	7,286	0	0	215	72	299	6,283	1,304,594	1,304,594	42.58	38.88
18	12/15/97 19:00	6,608	0	0	240	72	249	5,878	1,315,623	1,315,623	49.70	50.38
19	12/18/98 08:00	5,948	0	0	276	75	349	5,191	1,339,531	1,339,531	46.08	56.56
20	12/02/99 08:00	7,421	0	0	306	75	334	6,101	1,371,741	1,361,254	44.45	52.76
21	12/31/00 08:00	9,203	71	0	329	75	229	7,635	1,409,207	1,396,962	30.55	40.91
22	12/27/01 09:00	6,465	0	0	358	75	259	6,053	1,440,075	1,425,052	44.83	48.38
23	12/16/02 08:00	7,828	0	0	396	75	283	6,966	1,471,041	1,456,316	42.13	46.38
24	12/21/03 09:00	8,172	0	0	436	75	241	7,243	1,505,988	1,490,509	43.10	45.60
25	December-04								1,537,134	1,518,496	41.50	46.20
26	December-05								1,565,635	1,546,653	41.50	46.20
27	December-06								1,594,324	1,574,996	41.50	46.20
28												
29												
30												
31												
32												

Supporting Schedules: Recap Schedules

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006
___Prior Year Ended ___/___/___
___Historical Test Year Ended ___/___/___
Witness: Myers / Crisp

Line No.	Year	Month	(24) FPC MONTHLY ENERGY BY MAJOR CUSTOMER CLASS RESID	COM'L	INDUST	STR. LTG.	PUB. AUTH.	WHOLESALE	(25) IND SALES BY SUBSECTOR PHOSPHATE	NON-PHOS
1	2004	1	1,600,761	881,905	349,755	2,340	222,903	265,805	123,552	226,203
2	2004	2	1,386,066	760,461	301,960	2,180	218,718	257,875	85,064	216,896
3	2004	3	1,304,591	848,707	370,820	2,532	222,934	308,411	127,550	243,270
4	2004	4	1,186,689	874,499	345,799	2,353	235,583	289,864	98,759	247,040
5	2004	5	1,390,027	953,467	351,164	2,216	249,972	288,718	110,670	240,494
6	2004	6	1,928,679	1,112,598	354,226	2,396	258,702	305,204	93,969	260,257
7	2004	7	2,086,220	1,139,256	335,704	2,351	266,471	441,302	101,572	234,132
8	2004	8	1,976,090	1,109,776	346,763	2,310	269,870	465,456	95,284	251,479
9	2004	9	1,918,346	1,084,918	331,647	2,313	274,454	459,774	98,205	233,442
10	2004	10	1,773,691	1,035,843	284,939	2,300	277,513	452,035	68,535	216,404
11	2004	11	1,423,770	991,682	345,734	2,179	267,561	375,102	119,486	226,248
12	2004	12	1,372,338	940,424	350,115	2,457	251,065	391,545	109,920	240,195
13	2005	1	1,589,235	910,169	347,381	2,340	232,057	373,341	115,300	232,081
14	2005	2	1,521,212	863,894	335,741	2,180	235,839	373,371	115,300	220,441
15	2005	3	1,377,917	887,915	361,707	2,310	240,204	394,524	115,300	246,407
16	2005	4	1,336,444	961,173	367,800	2,353	253,618	418,458	115,300	252,500
17	2005	5	1,406,048	1,001,135	367,754	2,358	263,151	408,273	115,300	252,454
18	2005	6	1,814,664	1,132,351	375,710	2,384	295,968	416,760	115,300	260,410
19	2005	7	2,076,274	1,201,700	377,972	2,360	298,066	356,149	115,300	262,672
20	2005	8	2,144,926	1,219,976	379,653	2,420	302,647	365,804	115,300	264,353
21	2005	9	2,105,141	1,211,097	377,697	2,374	315,754	373,431	115,300	262,397
22	2005	10	1,824,032	1,128,701	373,519	2,290	295,011	351,612	115,300	258,219
23	2005	11	1,436,643	1,027,630	370,377	2,248	270,469	331,371	115,300	255,077
24	2005	12	1,440,581	978,472	367,612	2,453	261,590	301,210	115,300	252,312
25	2006	1	1,620,682	948,342	352,036	2,340	241,425	296,438	115,304	236,732
26	2006	2	1,573,474	901,136	343,307	2,180	245,369	220,328	118,237	225,070
27	2006	3	1,428,503	925,445	367,045	2,310	248,935	235,194	116,041	251,004
28	2006	4	1,391,014	999,923	382,117	2,353	262,791	252,587	124,984	257,133
29	2006	5	1,432,774	1,040,472	373,471	2,358	272,667	239,785	116,365	257,106
30	2006	6	1,853,107	1,174,109	380,418	2,384	306,454	265,689	115,282	265,136
31	2006	7	2,127,389	1,244,625	379,823	2,360	308,679	346,006	112,363	267,460
32	2006	8	2,196,218	1,263,111	387,090	2,420	313,452	364,379	117,889	269,201
33	2006	9	2,159,460	1,253,709	386,980	2,374	326,949	360,473	119,666	267,314
34	2006	10	1,873,695	1,169,294	377,593	2,290	305,657	307,246	114,386	263,207
35	2006	11	1,462,876	1,065,857	383,058	2,248	280,475	271,550	122,907	260,151
36	2006	12	1,480,360	1,015,494	371,596	2,453	271,397	256,096	114,176	257,420

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

___Prior Year Ended ___/___/___

___Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

Line No.	Year	Month	(26) FPC MONTHLY CUSTOMERS BY MAJOR CUSTOMER CLASS RESID	COM'L	INDUST	STR. LTG.	PUB. AUTH.	WHOLESALE
1	2004	1	1,348,442	155,289	2,727	1,886	20,240	21
2	2004	2	1,316,798	151,880	2,642	1,881	19,778	21
3	2004	3	1,391,176	160,455	2,799	1,872	20,793	26
4	2004	4	1,354,068	157,163	2,738	1,868	20,321	22
5	2004	5	1,364,646	158,735	2,734	1,860	20,604	21
6	2004	6	1,360,416	158,201	2,737	1,856	20,375	22
7	2004	7	1,352,339	157,222	2,730	1,853	20,370	33
8	2004	8	1,362,072	158,721	2,735	1,842	20,452	26
9	2004	9	1,377,987	160,762	2,725	1,848	20,749	27
10	2004	10	1,371,216	161,735	2,719	1,840	20,948	27
11	2004	11	1,386,736	163,690	2,742	1,835	21,096	24
12	2004	12	1,390,228	161,508	2,766	1,828	20,956	25
13	2005	1	1,379,271	159,281	2,813	1,850	20,784	24
14	2005	2	1,384,067	159,680	2,813	1,850	20,833	24
15	2005	3	1,386,726	159,875	2,813	1,850	20,877	24
16	2005	4	1,384,999	160,991	2,813	1,850	20,927	24
17	2005	5	1,382,717	161,070	2,813	1,850	20,974	24
18	2005	6	1,383,186	160,978	2,813	1,850	21,024	24
19	2005	7	1,385,134	161,366	2,813	1,850	21,071	23
20	2005	8	1,387,329	161,524	2,813	1,850	21,121	23
21	2005	9	1,388,688	161,810	2,813	1,850	21,170	23
22	2005	10	1,391,354	162,224	2,813	1,850	21,218	23
23	2005	11	1,396,841	162,604	2,813	1,850	21,267	23
24	2005	12	1,400,451	162,371	2,813	1,850	21,315	23
25	2006	1	1,404,625	162,429	2,813	1,850	21,364	23
26	2006	2	1,409,421	162,833	2,813	1,850	21,413	20
27	2006	3	1,412,086	163,033	2,813	1,850	21,458	20
28	2006	4	1,410,364	164,154	2,813	1,850	21,507	20
29	2006	5	1,408,089	164,237	2,813	1,850	21,555	20
30	2006	6	1,408,572	164,149	2,813	1,850	21,604	20
31	2006	7	1,410,532	164,540	2,813	1,850	21,652	20
32	2006	8	1,412,743	164,702	2,813	1,850	21,701	20
33	2006	9	1,414,119	164,992	2,813	1,850	21,750	20
34	2006	10	1,416,806	165,409	2,813	1,850	21,798	20
35	2006	11	1,422,316	165,790	2,813	1,850	21,847	20
36	2006	12	1,425,951	165,560	2,813	1,850	21,895	20

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of data shown:

_X_ Projected Test Year Ended 12/31/2006

____Prior Year Ended ___/__/____

____Historical Test Year Ended ___/___/___

Witness: Myers / Crisp

			27									
Line			FIRM RETAIL COINCIDENT MW				RETAIL	COMPANY	WHOLESALE COINCIDENT		PEF SYSTEM TOTAL CP	
No.	Year	Month	PRE DSM	NONDISP	DISPATCHABLE	NET FIRM	IS & CS MW	USE	FIRM MW	NONFIRM	FIRM MW	NONFIRM
1	2004	1	7,391	542	908	5,941	316	24	984	182	6,949	8,354
2	2004	2	7,146	525	761	5,860	272	24	686	207	6,570	7,809
3	2004	3	6,491	481	635	5,375	342	24	352	213	5,751	6,941
4	2004	4	6,665	358	231	6,076	310	24	357	215	6,457	7,214
5	2004	5	7,496	391	268	6,837	315	24	486	245	7,347	8,175
6	2004	6	7,896	408	333	7,155	318	24	679	275	7,858	8,784
7	2004	7	8,004	416	329	7,259	312	24	797	275	8,080	8,997
8	2004	8	8,063	427	351	7,285	311	24	775	275	8,084	9,021
9	2004	9	7,605	415	324	6,866	322	24	641	270	7,531	8,447
10	2004	10	7,037	381	201	6,455	318	24	381	405	6,860	7,784
11	2004	11	6,222	468	489	5,265	327	24	363	405	5,652	6,873
12	2004	12	7,368	540	562	6,266	317	24	737	420	7,027	8,326
13	2005	1	9,048	572	924	7,552	347	24	1,236	420	8,812	10,502
14	2005	2	7,485	554	755	6,176	346	24	711	420	6,911	8,432
15	2005	3	6,627	506	626	5,495	339	24	380	405	5,899	7,268
16	2005	4	6,858	371	213	6,274	322	24	383	410	6,681	7,627
17	2005	5	7,703	405	246	7,052	331	24	569	425	7,645	8,647
18	2005	6	8,103	423	304	7,376	332	24	613	275	8,013	8,924
19	2005	7	8,213	431	301	7,481	331	24	713	275	8,218	9,126
20	2005	8	8,269	443	321	7,505	331	24	693	275	8,222	9,150
21	2005	9	7,793	430	297	7,066	333	24	575	270	7,665	8,565
22	2005	10	7,216	395	187	6,634	327	24	388	255	7,046	7,816
23	2005	11	6,379	492	485	5,402	330	24	369	255	5,795	6,864
24	2005	12	7,531	570	558	6,403	329	24	820	270	7,247	8,404
25	2006	1	9,245	603	915	7,727	356	24	1,313	50	9,064	10,385
26	2006	2	7,632	583	746	6,303	330	24	748	50	7,075	8,201
27	2006	3	6,762	532	622	5,608	349	24	440	50	6,072	7,093
28	2006	4	7,053	383	199	6,471	325	24	450	50	6,945	7,519
29	2006	5	7,903	420	229	7,254	343	24	582	50	7,861	8,482
30	2006	6	8,305	438	281	7,586	336	24	797	50	8,407	9,074
31	2006	7	8,418	446	279	7,693	344	24	959	50	8,676	9,349
32	2006	8	8,473	458	297	7,718	345	24	936	50	8,678	9,369
33	2006	9	7,981	445	275	7,261	338	24	749	50	8,034	8,697
34	2006	10	7,395	408	176	6,811	342	24	608	50	7,443	8,011
35	2006	11	6,537	516	484	5,537	335	24	580	50	6,141	7,010
36	2006	12	7,695	600	557	6,538	343	24	1,128	50	7,690	8,640

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.		Witness	Page
10	I. GENERAL ASSUMPTIONS	Myers, Crisp	2
13	II. OPERATING ASSUMPTIONS	Myers, Crisp	7
16	III. CONSTRUCTION BUDGET ASSUMPTIONS	Myers	16
19	IV. BALANCE SHEET ASSUMPTIONS	Myers	18

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

I. General Assumptions

1 **FORECAST ASSUMPTIONS - CUSTOMER, ENERGY & DEMAND FORECAST**

2

3 Normal weather conditions are assumed over the forecast horizon. For kilowatt-hour sales projections normal weather is based on a historical thirty year average of service area weighted billing month degree days. Monthly coincident peak demand
4 projections are based on a thirty year historical average of system-weighted temperatures at time of seasonal peak.

5

6 The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 138 (February 2004) provide the basis for development of the customer
7 forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (February 2004) are also incorporated.

8

9 Within the Progress Energy Florida (PEF) service area the phosphate mining industry is the dominant sector in the industrial sales class. Five major customers accounted for nearly 30% of the industrial class MWh sales in 2003. These energy intensive
10 customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international
11 agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations which are heavily influenced by the state of
12 these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions.

13

14

15 A weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for
16 fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer producers to become more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase – as we have recently experienced - to the levels
17 just below that experienced in the late 1990 boom period. A significant risk to this projection lies in the continued high price of natural gas which is a major factor of production. Operations at several sites in the U.S. have already scaled back or shutdown due
18 to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

19

20

21 This forecast incorporates demand and energy reductions from PEF'S dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

22

23 This forecast assumes that FPC will successfully renew all future franchise agreements.

24

25 Expected energy and demand reductions from self-service cogeneration are also included in this forecast. FPC will supply the supplemental load of self-service cogeneration customers. While FPC offers "standby" service to all cogeneration customers, the
26 forecast does not assume an unplanned need for standby power.

27

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown

XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended
__ Historical Test Year Ended
Witness: Myers / Crisp

Line No.

I. General Assumptions (Cont'd)

1 **FORECAST ASSUMPTIONS - CUSTOMER, ENERGY & DEMAND FORECAST (Continued)**

2 This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. The ability of wholesale customers to switch suppliers has ended the company's obligation to serve these
3 customers beyond their contract life. As a result, the company does not plan for generation resources unless a long-term contract is in place. Current "all requirements" customers are assumed to not renew their contracts with FPC. Current "partial
4 requirements" contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur as new information received indicates that a wholesale customer has limited options in the marketplace to replace FPC
5 capacity more economically.
6
7 Progress Energy Florida supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements customers' demand and energy is assumed to grow at a rate that approximates their historical
8 trend. Cities served on this basis include Bartow, Chattahoochee, Mt Dora, Newberry, Quincy and Williston. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations received by PEF in an annual "declaration letter" as
9 of May 31, 2004. The forecast of energy and demand to PR customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so.
10 Contracts for PR service included in this forecast are with FMPA, the cities of New Smyrna Beach, Tallahassee and Homestead, and other utilities such as Reedy Creek Utilities, Florida Power & Light and Tampa Electric Company.
11
12
13 A significant majority of PEF's wholesale load is served to Seminole Electric Cooperative, Inc. (SECI) under several contracts. PEF's arrangement with SECI is to serve "supplemental" service over and above stated levels they commit to supply themselves.
14 SECI's projection of their system's requirements in the PEF control area provides the basis for the level of service needed to be "supplemented by PEF. This forecast also incorporates two firm bulk power contracts with SECI. The first is a 150 MW stratified
15 intermediate demand (Oct 1995 contract) that is projected to remain until 2013. It increases by an additional 150 MW beginning in June 2006.
16
17 The economic outlook for this forecast calls for a gradual strengthening of national and State economic growth as the recovery from the recent recession takes hold and terrorism fears subside. As this forecast was developed signs of an improving economy
18 were beginning to be reflected in reported GDP growth. Employment growth had just commenced after a long period of contraction. Monetary policy announcements suggested a return to more normal levels of interest rates and monetary growth. A fifty-
19 year low in market interest rates - coaxed by the Federal Reserve Board (FED) - and lower Federal tax rates appear to have stimulated the U.S. economy enough to warrant a less accommodative monetary policy.
20
21
22 The extremely accommodative fiscal and monetary policies since late 2001, the passage of time from the error attack of 9/11, and the working off of excess investment of the "bubble" economy, have set up the U.S. and Florida economy on track for
23 reasonable consistent growth for the foreseeable future. As consumer confidence rebounds more reasonable returns on investment will enable businesses to resume hiring. A weaker dollar should make domestic producers more competitive.
24
25
26 Particular sectors of the economy that have been performing well include the housing industry and the individual consumer. Both have been credited with fueling the limited economic advances of the past two years. The multi-generational low in interest
27 rates and expansion of credit has stimulated an unprecedented level of housing construction. The record level of mortgage refinancing and lowering of Federal taxes have acted to put added money in people's pockets, further stimulating demand.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

I. General Assumptions (Cont'd)

FORECAST ASSUMPTIONS - CUSTOMER, ENERGY & DEMAND FORECAST (Continued

While most signs point toward an improving economic environment, there are some risks that were considered in the development of this forecast. Market prices for energy have been very high for an extended period at this point. Historically, high oil prices have resulted in starving economic growth. Fears of a shortage in supplies has kept natural gas prices high as well and has placed increased burden on manufacturers who rely upon reasonably priced fuel as a major source of production.

An additional risk comes as the FED increases interest rates. Some economists believe that the housing sector has been over-simulated by record-low interest rates. Others believe that Americans have "loaded up" on debt and will be negatively impacted by higher debt-service as interest rates rise. The FED must carefully balance the risks staving off higher inflation without starving economic growth. Higher inflation could force up market-driven interest rates faster than the FED would prefer. This event would certainly hurt the housing sector as well as consumer spending. This forecast tries to balance this and other risks by incorporating the National and State economic projections developed by Economy.Com.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. Obviously, many factors influence the pace of in-migration to Florida but there is one broad, demographically created influence one can expect during the next few years. The University of Florida's latest population projection (February 2004) shows a return to more normal levels of growth in Florida population as we move into the mid-decade. This is due to economy-related conditions and characteristics of the age cohorts reaching retirement age this decade.

CUSTOMER GROWTH RATE = **1.85%** SALES GROWTH RATE = **3.00%**

GENERAL INFLATION RATES: The projected inflation rate for 2006 was 2.0%. However, the 2006 Budget was based on specific cost estimates for 2006. When specific information for 2006 costs was not available, the general inflation rate was used.

WAGE AND SALARY INCREASE: 3.25% based upon assessment of: (1) competition; (2) impact of inflation (3) corporate bargaining unit agreement; and (4) merit increases for all non-bargaining unit employees beginning in April 2006 (for an effective annual increase of 2.5%).

COMMON STOCK DIVIDENDS: Dividends in 2006 (in millions): $45.8 for each quarter

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

I. General Assumptions (Cont'd)

PROPERTY TAX PAYMENT - 2006 Property Taxes to be paid in November, 2006.

FRANCHISE FEE PAYMENT - Paid to cities on a monthly basis

FINANCINGS -

There was a new issue of $350,000,000 forecasted in June of 2005. This new issue is a 3 year floating rate note, with interest rates between 2.74% and 4.10%. There are no new issues in the 2006 forecast. 2006 financing needs are assumed to be met with additional borrowings under the Company's commercial paper program and through short-term debt. $48.3 million of long-term debt redemptions related to sinking fund payments and scheduled maturities for 2006 are included in the cash flow forecast.

RESIDUAL FUEL OIL ASSUMPTIONS

Crude Oil supply will remain relatively stable through the forecast period.

U.S. Government policy is not expected to impact the residual or light oil market except that environmental restrictions will increase the relative demand and price of lower sulfur oils

Weather is assumed to be normal throughout the period.

Fuel oil demand will remain relatively stable throughout the period except that the demand for lower sulfur oil will gradually displace the demand for higher sulfur oil

Refineries over the long-term will make product changes to balance residual fuel supply with current and future demand.

Mismatches between the two above mentioned factors combined with uncertain weather will cause periodic mismatches in supply/demand balances and wider short term fluctuations in prices than presented in this forecast

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

I. General Assumptions (Cont'd)

DISTILLATE FUEL OIL ASSUMPTIONS

Crude Oil supply will remain relatively stable through the forecast period.

U.S. Government policy is not expected to impact the residual or light oil market except that environmental restrictions will increase the relative demand and price of lower sulfur oil such as distillate fuel oil

Weather is assumed to be normal throughout the period.

Low sulfur #2 oil demand will increase relative to high sulfur #2 oil as it is used as a back-up fuel for natural gas as well as on-road diesel fuel.

NATURAL GAS ASSUMPTIONS

Overall supply of natural gas will be adequate except during extreme weather and during pipeline outages.

Interruptible supply from Florida Gas Transmission and South Georgia Natural Gas will be available in limited quantities as the pipeline capacity is utilized for firm supply contracts for Progress Energy Florida.

The Gulfstream Natural Gas pipeline is not expected to be fully subscribed in the 2005/06 timeframe.

COAL ASSUMPTIONS

Coal Price Projections are provided by Progress Fuels Corporation and represent an estimate of PFC's price to Progress Energy Florida for coal delivered to the plant sites in accordance with the delivery schedules projected. It assumes **environmental restrictions on** coal quality remain in effect as per current plans: 2.1 lbs. per million BTU sulfur dioxide limit for C.R. 1&2 and 1.2 lbs. per million BTU sulfur dioxide limit for C.R. 4&5. However expected environmental restrictions do **impact the market for low sulf**ur coals causing demand and prices to be higher than would otherwise be expected.

NUCLEAR FUEL EXPENSE ASSUMPTIONS

Nuclear Fuel amortization projections (nuclear fuel expense) are based on a combination of actual dollar expenditures, estimates of future cash expenditures for contractual commitments, and the amount of energy (BTU's) extracted during a particular cycle from each batch utilized.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

II. Operating Assumptions

Income Statement

Operating Revenue

A. **Base Revenue - KWH sales** are determined by the Load Forecasting Department (See general assumptions for customer, energy, and demand forecast).

B. **Fuel Revenue - No change in** the methodology presently in place for the recovery of fuel expense.

C. **Energy Conservation Revenue** - No change in the methodology presently in place for the recovery of energy conservation expenses.

D. **Franchise Revenue - Assumed** that an average historic tax rate would be representative for 2006.

E. **Other Operating Revenue** - Pole attachments, rentals, and miscellaneous other service revenues assumed that current rental agreements would remain in effect during 2006 and that service revenues would be impact by the forecasted customer growth rate

F. **Revenue Sharing - No revenue** sharing assumed after December 31, 2005.

Fuel Expense and Purchased Power

Fuel expense and purchased power is determined by the Company's production cost simulation model. The model uses input from fuel price forecasts, purchased power contracts, generating unit operating characteristics, maintenance outage schedules and other pertinent data to determine the most economical way to satisfy the corporate forecast of demand and energy.

Depreciation Expense

Depreciation expense is determined using forecasted 2006 monthly Electric Plant in Service. Depreciation rates were approved by the Florida Public Service Commission in Docket No.971570-E.I., Order No. PSC-98-1723-FOF-EI, December 18, 1998. Dismantlement and decommissioning accruals were suspended as part of the last rate case settlement, Docket No. 000824-EI. Amortization of intangible plant, ECCR plant, and the Sebring regulatory assets was based on currently approved rates.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

II. Operating Assumptions (Cont'd)

Income Statement (Cont'd)

Amortization of Limited Plant

Amortization of intangible plant, ECCR plant, and the Sebring regulatory assets were based on current approved rates.

Taxes Other Than Income Taxes

Taxes other than income taxes include property taxes, payroll related taxes, revenue related taxes. The property taxes reflect an estimate of next year's taxes by the tax department, payroll related taxes were estimated based on **budgeted payroll and rates** in current law. Revenue related taxes are based on current law and franchise agreement and the budgeted revenues.

Income Taxes

Federal and state statutory tax rates are based upon law in effect at the time the forecast was prepared. Temporary timing differences are fully normalized. Investment Tax Credit is amortized over the remaining lives of related **equipment as required by** the Internal Revenue Service under Section 46 of the IRS Code. Excess deferred income taxes for protected items are flowed back in accordance with Section 203(e) of the Tax Reform Act of 1986.

Other Income and Deduction (Net)

Donations and other deductions are based on the budget submission from the business units. Income on the Life Insurance (Rabbi Trust) is based on assumptions of project cost and market conditions. Non-operating income is **based on projections from t**he business units of the non-regulated activity.

Gross Interest Expense

Interest expense for Long Term Debt is determined by the series interest rate applied to the amount outstanding. There was a new issue of $350,000,000 forecasted in June of 2005. This new issue is a 3 year floating rate note, with **interest rates between 2.74% a**nd 4.10%. There are no new issues in the 2006 forecast. Interest expense on Short Term Debt is determined by applying the assumed rate of 3.40-4.40% on the average outstanding amount each month. Interest on Customer Deposits is calculated using a blended interest rate applied against the projected total customer deposit balance. Customer deposit balance is based on historical relationship between total deposits and number of customers.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: **For a projected** test year, provide a schedule of assumptions used in **developing projected** or estimated data. At a minimum, state **assumptions used** for balance sheet, income statement, and sales **forecast.**

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ **Prior Year Ended**

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

II. Operating Assumptions (Cont'd)

Average Annual Net Unit Heat Rates for 2006

Line No.	(A) Plant & Unit		(B) Average Net Heat Rate (BTU/KWH) *	(A) Plant & Unit		(B) Average Net Heat Rate (BTU/KWH) *
1						
2						
3						
4	**Steam**			**Peakers**		
5	Anclote	1	10,529	Avon Park	1	17,572
6	Anclote	2	10,559	Avon Park	2	17,639
7	Bartow	1	10,983	Bartow	1	14,523
8	Bartow	2	11,427	Bartow	2	15,278
9	Bartow	3	10,357	Bartow	3	14,495
10	Crystal	1	10,168	Bartow	4	15,066
11	Crystal	2	9,355	Bayboro	1	14,554
12	Crystal	3	10,303	Bayboro	2	14,533
13	Crystal	4	9,491	Bayboro	3	14,388
14	Crystal	5	9,475	Bayboro	4	14,541
15	Hines	1	7,112	DeBary	1	13,968
16	Hines	2	6,948	DeBary	2	13,960
17	Hines	3	6,996	DeBary	3	13,967
18	Suwannee	1	12,621	DeBary	4	13,970
19	Suwannee	2	13,593	DeBary	5	13,969
20	Suwannee	3	11,497	DeBary	6	13,969
21	Tiger Bay	1	8,201			
22						
23						
24						
25						
26						
27						

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

II. Operating Assumptions (Cont'd)

Average Annual Net Unit Heat Rates for 2006 (Cont'd)

	(A) Plant & Unit		(B) Average Net Heat Rate (BTU/KWH) *	(A) Plant & Unit		(B) Average Net Heat Rate (BTU/KWH) *
	Peakers			**Peakers**		
	DeBary	7	13,834	Rio Pinar	1	18,404
	DeBary	8	13,760	Suwannee	1	14,013
	DeBary	9	13,808	Suwannee	2	13,786
	DeBary	10	13,792	Suwannee	3	14,096
	Higgins	1	18,040	Turner	1	18,902
	Higgins	2	18,464	Turner	2	18,898
	Higgins	3	16,343	Turner	3	15,289
	Higgins	4	16,334	Turner	4	15,573
	InterCity	1	14,397	Univ of Fla	1	9,481
	InterCity	2	14,329			
	InterCity	3	14,320			
	InterCity	4	14,632			
	InterCity	5	14,272			
	InterCity	6	14,407			
	InterCity	7	13,784			
	InterCity	8	13,638			
	InterCity	9	13,789			
	InterCity	10	13,847			
	InterCity	11	12,275			
	InterCity	12	12,777			
	InterCity	13	12,776			
	InterCity	14	12,766			

Notes: * Includes start-up BTU's.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

II. Operating Assumptions (Cont'd)

Outage Rates for 2006

Line No.	Steam Plant		(A) Equivalent Forced Outage Rate	(B) Maintenance Outage Rate *	(C) Total Unavailable Outage Rate
4	Anclote	1	5.19	0.00	5.19
5	Anclote	2	5.94	0.00	5.94
6					
7	Bartow	1	14.20	0.00	14.20
8	Bartow	2	4.53	0.00	4.53
9	Bartow	3	9.78	0.00	9.78
10					
11	Crystal River	1	8.50	0.00	8.50
12	Crystal River	2	12.34	0.00	12.34
13	Crystal River	3	3.00	0.00	3.00
14	Crystal River	4	4.61	0.00	4.61
15	Crystal River	5	4.41	0.00	4.41
16					
17	Hines	1	2.76	0.00	2.76
18	Hines	2	3.00	0.00	3.00
19	Hines	3	3.00	0.00	3.00
20					
21	Suwannee	1	2.89	0.00	2.89
22	Suwannee	2	1.82	0.00	1.82
23	Suwannee	3	6.96	0.00	6.96
24					
25	Tiger Bay	1	5.35	0.00	5.35
26					

27 Notes: * Maintenance outages are incorporated in the forced outages.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

II. Operating Assumptions (Cont'd)

Outage Rates for 2006 (Cont'd)

Line No.	Peaker Site and Units		(A) Equivalent Forced Outage Rate	(B) Maintenance Outage Rate *	(C) Total Unavailable Outage Rate
4	Avon Park	1,2	1.35	0.00	1.35
6	Bartow	1,2,3,4	2.49	0.00	2.49
8	Bayboro	1,2,3,4	0.48	0.00	0.48
10	DeBary	1,2,3,4,5,6	1.97	0.00	1.97
11	DeBary	7,8,9,10	2.30	0.00	2.30
13	Higgins	1,2,3,4	2.60	0.00	2.60
15	InterCity	1,2,3,4,5,6	0.96	0.00	0.96
16	InterCity	7,8,9,10	1.09	0.00	1.09
17	InterCity	11	0.89	0.00	0.89
18	InterCity	12,13,14	1.70	0.00	1.70
20	Rio Pinar	1	7.27	0.00	7.27
22	Suwannee	1,2,3	0.34	0.00	0.34
24	Turner	1,2	4.36	0.00	4.36
25	Turner	3,4	2.64	0.00	2.64
27	Univ of Fla	1	0.50	0.00	0.50

Notes: * Maintenance outages are incorporated in the forced outages.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

II. Operating Assumptions (Cont'd)

Planned Maintenance for 2006

Line No.	Steam Plant		(A) Start Date	(B) End Date	(C) Outage Duration (Days)	(D) Total Days	
4	Anclote	1	November 18	December 1	14	14	
5	Anclote	2	April 1	May 12	42	42	
6							
7	Bartow	1	September 30	November 10	42	42	
8							
9	Crystal River	2	March 11	**March 24**	14	14	
10							
11	Hines	1	March 18	**March 31**	14	14	
12	Hines	1	October 21	November 3	14	14	
13							
14	Hines	2	April 1	April 14	14	14	
15	Hines	2	April 15	April 28	14	14	(260 MW Only)
16	Hines	2	November 4	November 17	14	14	
17	Hines	2	November 18	December 1	14	14	(260 MW Only)
18							
19	Suwannee	1	November 4	November 17	14	14	
20	Suwannee	2	February 18	March 3	14	14	
21	Suwannee	2	November 18	December 1	14	14	
22							
23	Tiger Bay	1	April 29	May 5	7	7	
24	Tiger Bay	1	December 2	December 8	7	7	

Notes: i) Units not listed have no planned maintenance during 2006.

ii) Planned maintenance for 2006 is based on: "2006 Generating Unit Maintenance Outage Schedule" dated April 22, 2004 and "FL_Nuclear Outage Schedule_2004_0604.xls".

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

II. Operating Assumptions (Cont'd)

Net Unit Capacity Ratings for 2006

Line No.	Plant and Unit		(A) Net * Summer (Mw)	(B) Net * Winter (Mw)	
1					
2					
3					
4	Anclote	1	498	522	
5	Anclote	2	495	522	
6					
7	Bartow	1	121	123	
8	Bartow	2	119	121	
9	Bartow	3	204	208	
10					
11	Crystal	1	379	383	
12	Crystal	2	486	491	
13	Crystal	3 **	769	788	
14	Crystal	4	720	735	
15	Crystal	5	717	732	
16					
17	Hines	1	482	529	
18	Hines	2	516	582	
19	Hines	3	516	582	(Planned in-service date of December 2005)
20					
21	Suwannee	1	32	33	
22	Suwannee	2	31	32	
23	Suwannee	3	80	81	
24					
25	Tiger Bay	1	207	223	
26	Total Steam		6,372	6,687	
27					

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO: 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

II. Operating Assumptions (Cont'd)

Net Unit Capacity Ratings for 2006 (Cont'd)

Line No.	Peaker Site and Units		(A) Net * Summer (Mw)	(B) Net * Winter (Mw)
4	Avon Park	1,2	52	64
6	Bartow	1,2,3,4	187	219
8	Bayboro	1,2,3,4	184	232
10	DeBary	1,2,3,4,5,6	324	390
11	DeBary	7,8,9,10	343	372
13	Higgins	1,2,3,4	122	134
15	InterCity	1,2,3,4,5,6	294	366
16	InterCity	7,8,9,10	352	376
17	InterCity	11	143	170
18	InterCity	12,13,14	252	294
20	Rio Pinar	1	13	16
22	Suwannee	1,2,3	164	201
24	Turner	1,2	26	32
25	Turner	3,4	128	162
27	Univ of Fla	1	35	41
28	Total Peakers		2,619	3,069
30	System Total		8,991	9,756

Notes:

* All ratings are maximum dependable capability. Summer ratings are effective May 1 through October 31. Winter ratings are effective November 1 through April 30.

** Crystal River 3 net ratings have been adjusted for sale of 8.2% of capacity.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

III. Construction Budget Assumptions

Facility Assumptions - Functional Area

Production Plant

The forecast 2005 expenditures include $67.8m, and $1.7m in 2005, for the construction of a new combined cycle unit at the Hines Energy Complex. Planned in-service date for this unit is Fall, 2005. This unit will add generating capacity of approximately 516 MW. Additionally there is about $38.2m in 2005, and $91.4m in 2006, planned for construction of combined cycle unit #4 at the Hines Energy Complex, working toward an expected in-service date of Fall, 2007. This unit will add generating capacity of approximately 460 MW.

Replacement of the steam generator at the Crystal River nuclear plant is expected to require capital expenditures of about $36.3m in 2005, and $21.7m in 2006. The project will be placed in service at the completion of the refueling outage in the Fall of 2009.

Coal yard redesign and refurbishment of coal handling equipment for the Crystal River fossil units is expected to require expenditures of $3.1m in 2005 and $31.1m in 2006. The work will consist of several distinct projects, and be placed in service primarily in the fall of 2007.

In general, all projects are justified on the basis of environmental, capacity, availability, safety, regulatory requirements, and/or discretion (where benefits exceed cost).

Transmission and Distribution Plant

"Delivery plant expenditures of $277m in 2005 and $272m during 2006 include those expenditures required to provide the infrastructure for the projected customer growth, and maintain or improve the quality of service and reliability to existing customer base. None of these expenditures individually exceed 0.2% of plant in service. In general, all projects are justified on the basis of environmental, capacity, availability, safety, regulatory requirements, and/or discretion (where benefits exceed cost).

General Plant

General plant expenditures are used to a) provide proper equipment for new employees with proper equipment to perform their jobs, b) replace existing equipment that can not be properly maintained or repaired.

NUCLEAR FUEL

Purchases of Nuclear Fuel are expected to be approximately $52m in 2005.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION - 7.81%

The system level of CWIP allowed in rate base was assumed to be the amount associated with work order projects not eligible for AFUDC and work order projects ready for service but accruing additional expenditures. This amount is consistent with the amount authorized at the time this forecast was prepared.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX **Projected Test** Year Ended 12/31/2006

__ **Prior Year Ended**

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

III. Construction Budget Assumptions (Cont'd)

1 **OVERHEADS**

2 Burden rates for benefits, payroll taxes and exceptional hours are applied to all charges for productive labor.

3

4

5 Budgeted base salaries are allocated between productive labor and exceptional hours. This allocation is based on the average days taken off in 2003 for company observed holidays, employee preference holidays and vacation days as
6 a percentage of work days in the year. For the 2006 budget, 86.21% of base wages was considered productive labor, and 13.79% of base wages was considered exceptional hours. This allocation results in an exceptional hours burden
7 rate applied to productive labor of 16.0%. For the Energy Delivery business unit, the exceptional hours burden rate is adjusted to 19.5% based on higher average vacation days taken.

8

9 Productive labor is burdened at a 9.55% rate for payroll taxes (including FICA, Medicare, and federal and state unemployment taxes

10

11 The employee benefit burden rate is based on the following costs for 2006 ($ in millions)

12

13	Employee health care	28.6
14	Retiree health care	26.3
15	Employee life insurance	0.8
16	401(k) plan	10.6
17	FAS 112 health / Life	1.2
18	FAS 112 salary continuation	1.0
19	Total	68.5
20		
21	Benefits burden rate	34.0%

22

23 The resulting total burden rate applied to productive labor is as follows:

24

25	Exceptional hours	16.00%
26	Payroll taxes	9.55%
27	Benefits	34.0%
28	Total burden rate	59.6%

29

30 Variances in the budget for total burdened benefits versus total expected costs are adjusted at the corporate level.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

IV. Balance Sheet Assumptions

1 **UTILITY PLANT**

2

3 **ELECTRIC PLANT IN SERVICE**

4 The timing and dollar amount of additions related to major projects is based on the current budget submissions from the business units. The dollar amount for minor project additions and blanket additions is
5 also based on the current budget submission from the business units. The timing of these additions is based on a percentage of the prior month CWIP balance and historical trends. Retirements are based on
6 known amortization schedules and historical trends.

7

8 **PLANT PURCHASED OR SOLD**

9 There is no activity projected for this account during 2005 or 2006.

10

11 **ELECTRIC PLANT HELD FOR FUTURE USE**

12 Existing electric plant held for future use will not be placed in service before December 31, 2005. There are no additional closings to this account projected for 2005 or 2006.

13

14

15 **CONSTRUCTION WORK IN PROGRESS**

16 Total expenditures are derived from the 2005/2006 Corporate Construction Budget. Allowance for Funds Used During Construction is calculated at an annual rate of 7.81%

17

18

19 **ACCUMULATED PROVISION FOR DEPRECIATION**

20 Depreciation expense is derived from the Budgeted income statement. Plant retirements are taken from monthly Electric Plant in-service activity.

21

22 **ACCUMULATED AMORTIZATION OF ELECTRIC PLANT**

23 The only activity affecting this account is the monthly amortization expense from the income statement, except for the storm cost amorization expense which reduces the regulatory asset.

24

25

26 **NUCLEAR FUEL**

27 Purchases of Nuclear Fuel are expected to be approximately $52m in 2005. Other changes represent the forecasted nuclear fuel burn from the Production Simulation Model.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

IV. Balance Sheet Assumptions (Continued)

NON-UTILITY PROPERTY

Represents the change resulting from additions and depreciation on property assets utilized in the non-regulated business.

ACCUMULATED PROVISION FOR DEPRECIATION - NON-UTILITY

The monthly balance will increase by the provision for depreciation.

OTHER PROPERTY AND INVESTMENTS

OTHER INVESTMENTS

The monthly balance will remain unchanged for the budget year.

OTHER SPECIAL FUNDS

Primarily the Nuclear Plant Decommissioning Fund - The funding for decommissioning costs will occur monthly based on the last allowed level of expenses authorized by the FPSC and FERC. The balance remains unchanged due to the 2002 Rate Case Settlement agreement in Docket No. 000824-EI, where the nuclear decomissioning expense accrual was suspended. Income taxes are calculated on taxable fund earnings and are paid quarterly. The Company segregates the funds into Retail and Wholesale funds and qualified/non-qualified. The qualified funds are funded with pre-tax dollars; the non-qualified funds with after tax dollars.

CURRENT AND ACCRUED ASSETS

CASH

Monthly balances are derived from the budgeted cash forecast .

SPECIAL DEPOSITS

Monthly balances related to deposits on mortgaged property sold or destroyed are assumed to be zero.

WORKING FUNDS

Assumed that the monthly balance of working funds for employees and various company offices are assumed to be zero.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

IV. Balance Sheet Assumptions (Continued)

CURRENT AND ACCRUED ASSETS (CONTINUED)

TEMPORARY CASH INVESTMENT

Temporary cash investments are a function of the budgeted cash receipts and disbursements.

NOTES RECEIVABLE

Notes receivable is assumed to remain constant for the budget year.

NOTES AND ACCOUNTS RECEIVABLE FROM ASSOCIATED COMPANIES

The monthly balances in accounts receivable from associated companies will remain constant for the year.

ACCOUNTS RECEIVABLE

The monthly balances for Customer Accounts Receivable was projected assuming that a specified percent of a forecasted months revenue would be received as cash that month and other amounts would be collected in subsequent months.

MATERIALS AND SUPPLIES

The monthly net additions for materials and supply inventory are derived from the Company's Corporate Model and will remain constant throughout the year.

FUEL STOCK

The fuel inventory level was projected by subtracting the estimated cost of the fuel burn as determined by the Production Simulation Model and the average inventory cost and adding the projected costs to purchase additional fuel at forecasted prices sufficient to bring inventory to targeted quantity levels.

PREPAYMENTS

Monthly balances based on expected payment dates for insurance and the related amortization period for these amounts

ACCRUED UTILITY REVENUES

It was assumed that the accrued utility revenue balance would be equal to the beginning balance; therefore the accrued utility revenues are forecast at a constant level.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

IV. Balance Sheet Assumptions (Continued)

DEFERRED DEBITS

This account captures such items as the ECCR and ECRC current month deferral and the amortization of the prior month's deferral. In addition, it includes Sebring Rider interest accrual and the GPIF amortization. It was assumed that the average of the remaining deferred debits would be equal to the beginning balance; therefore they are forecast at a constant level.

PROPRIETARY CAPITAL

COMMON STOCK

No changes are expected during 2002

PREFERRED STOCK

No changes are expected during the year.

OTHER PAID IN CAPITAL

No changes are expected during the year.

UNAPPROPRIATED RETAINED EARNINGS

The projected monthly balances are expected to increase by the monthly earnings applicable to common from the Budgeted income statement and will be reduced by expected common dividends to be paid during the year

LONG-TERM DEBT

There was a new issue of $350,000,000 forecasted in June of 2005. This new issue is a 3 year floating rate note, with interest rates between 2.74% and 4.10%. There are no new issues in the 2006 forecast. 2006 financing needs are assumed to be met with additional borrowings under the Company's commercial paper program and through short-term debt. $48.3 million of long-term debt redemptions related to sinking fund payments and scheduled maturities for 2006 are included in the cash flow forecast.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

IV. Balance Sheet Assumptions (Continued)

OTHER NON-CURRENT LIABILITIES

MISCELLANEOUS OPERATING RESERVES

This account captures such items as DOE Facility Decommissioning, Pension Liability, Deferred SERP, Medical & Life Insurance reserves, Environmental liability, End of life nuclear fuel, and last core nuclear fuel. It was assumed that the average of the remaining miscellaneous operating reservess would be equal to the beginning balance; therefore they are forecast at a constant level.

CURRENT AND ACCRUED LIABILITIES

NOTES PAYABLE

Short-term borrowing requirements are as determined in the Budgeted cash forecast.

ACCOUNTS PAYABLE

The monthly balances for fuel, purchased power, trade payables and Nuclear Fuel Disposal Cost are derived from the Company's Corporate Model.

ACCOUNTS PAYABLE TO ASSOCIATED COMPANY

The monthly balances are derived from information provided by Associated Companies.

CUSTOMER DEPOSITS

The growth rate is based upon a historical trends.

TAXES ACCRUED

The monthly balances increase by the accruals shown on the income statement and decrease by the cash payments.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

IV. Balance Sheet Assumptions (Continued)

1 **CURRENT AND ACCRUED LIABILITIES (CONT)**

2 **INTEREST ACCRUED**

3 **The monthly balances increase by the ac**cruals shown on the income statement and decrease by the cash payments.

4

5 **DIVIDENDS DECLARED - COMMON STOCK**

6 Dividends declared and paid in the current month.

7

8

9 **OTHER CURRENT LIABILITIES**

10 Change reflects the loss in the Company Owned Life Insurance (COLI). The monthly balance of all other accounts in this group to remain constant for the year.

11

12

13 **OTHER TAX COLLECTIONS PAYABLE**

14 The monthly tax accruals comes from the Budget income statement. Payments for other taxes are derived from an analysis of each specific "Other Tax"

15

16

17 **OTHER LIABILITIES**

18 **REGULATORY LIABILITY - SFAS 109**

19 This balance changes to reflect the amortization of the SFAS 109 Regulatory Liability

20

21 **OTHER DEFERRED CREDITS**

22 **In 2006, it was assumed that** the other deferred credit balance would be equal to the beginning balance; therefore the other deferred credit are forecast at a constant level.

23

24

25

26

27

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA INC.

DOCKET NO. 050078-EI

Explanation: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement, and sales forecast.

Type of Data Shown:

XX Projected Test Year Ended 12/31/2006

__ Prior Year Ended

__ Historical Test Year Ended

Witness: Myers / Crisp

Line No.

IV. Balance Sheet Assumptions (Continued)

1 **OTHER LIABILITIES (cont'd)**

2

3 **ACCUMULATED DEFERRED INVESTMENT TAX CREDIT/ACCUMULATED DEFERRED INCOME TAXES**

4 The net monthly balance for investment tax credit is determined from the activity shown in the Budget income statement.

5

6

7 **OTHER DEFERRED LIABILITIES**

8 It was assumed that the other deferred liabilities balance would be equal to the beginning balance; therefore the other deferred liabilities are forecast at a constant level.

9

10

11 **ASSET RETIREMENT OBLIGATIONS FAS 143**

12 The change in this balance represents the accretion expense associated with FAS 143

13

14

15

16

17

18

19

20

21

22

23

24

25

26

27

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC

Docket No. 050078-EI

Explanation: Supply a propsed public notice of the company's request for a rate increase suitable for publication

Type of data shown:

XX Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Year Ended 12/31/2004
Witness: Habermeyer

Line No

NOTICE TO CUSTOMERS OF
PROGRESS ENERGY FLORIDA

On April 29, 2005, Progress Energy Florida filed a petition with the Florida Public Service Commission requesting an increase in its base rates, effective January 1, 2006. The FPSC has assigned Docket No. 050078-EI to Progress Energy's request.

The primary reasons for the requested base rate increase include, but are not limited to: (1) The addition of two new generating units providing over 1,000 megawatts of power to meet the needs of Progress Energy Florida's customers; (2) increased capital costs and operation and maintenance expenses necessary to provide reliable and quality electric service to customers; and (3) the need to replenish Progress Energy Florida's depleted storm damage reserve.

The FPSC will hold service hearings throughout Progress Energy Florida's service territory to receive the testimony of customers regarding the quality of service provided by Progress Energy Florida and its requested increase in base rates. The dates and locations of the service hearings will be published in a separate notice after they have been scheduled.

A copy of Progress Energy's petition for an increase in its base rates and supporting documentation is available for inspection during regular business hours at the Progress Energy Florida office located at 100 Central Avenue in St. Petersburg, Florida. Information about the requested base rate increase is also available at Progress Energy's website, www.progress-energy.com and at the FPSC's website, www.psc.state.fl.us/.