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, 2005

OR

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

For the transition period from ____________ to ___________

Commission File Number	Exact name of registrants as specified in their charters, state of incorporation, address of principal executive offices, and telephone number	I.R.S. Employer Identification Number
1-15929	Progress Energy **Progress Energy, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-2155481
1-3382	**Carolina Power & Light Company** **d/b/a Progress Energy Carolinas, Inc.** 410 South Wilmington Street Raleigh, North Carolina 27601-1748 Telephone: (919) 546-6111 State of Incorporation: North Carolina	56-0165465
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
Progress Energy, Inc.:	
Common Stock (Without Par Value)	New York Stock Exchange
Carolina Power & Light Company:	None
Florida Power Corporation:	None

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

Progress Energy, Inc.:	None
Carolina Power & Light Company:	$5 Preferred Stock, No Par Value
	Serial Preferred Stock, No Par Value
Florida Power Corporation:	None

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Act.

Progress Energy, Inc. (Progress Energy)	Yes	(X)	No	( )
Carolina Power & Light Company (PEC)	Yes	(X)	No	( )
Florida Power Corporation (PEF)	Yes	( )	No	(X)

Indicate by check mark whether each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Progress Energy	Yes	( )	No	(X)
PEC	Yes	( )	No	(X)
PEF	Yes	( )	No	(X)

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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.

Progress Energy	( )
PEC	(X)
PEF	(X)

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act.:

Progress Energy	Large accelerated filer (X)	Accelerated filer ( )	Non-accelerated filer ( )
PEC	Large accelerated filer ( )	Accelerated filer ( )	Non-accelerated filer (X)
PEF	Large accelerated filer ( )	Accelerated filer ( )	Non-accelerated filer (X)

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Act).

Progress Energy	Yes	( )	No	(X)
PEC	Yes	( )	No	(X)
PEF	Yes	( )	No	(X)

As of June 30, 2005, the aggregate market value of the voting and nonvoting common equity of Progress Energy held by nonaffiliates was $11,332,332,138. As of June 30, 2005, the aggregate market value of the common equity of PEC held by nonaffiliates was $0. All of the common stock of PEC is owned by Progress Energy. As of June 30, 2005, the aggregate market value of the common equity of PEF held by nonaffiliates was $0. All of the common stock of PEF is indirectly owned by Progress Energy.

As of February 28, 2006, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares
Progress Energy	Common Stock (Without Par Value)	252,289,683
PEC	Common Stock (Without Par Value)	159,608,055
PEF	Common Stock (Without Par Value)	100

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Progress Energy and PEC definitive proxy statements for the 2006 Annual Meeting of Shareholders are incorporated into PART III, ITEMS 10, 11, 12 , 13 and 14 hereof.

This combined Form 10-K is filed separately by three registrants: Progress Energy, PEC and PEF (collectively, the Progress Registrants). Information contained herein relating to any 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 registrants.

PEF meets the conditions set forth in General Instruction I (1) (a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format permitted by General Instruction I (2) to such Form 10-K. PEF is not an asset-backed issuer, as defined in Item 11101 of Regulation AB.

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GLOSSARY OF TERMS

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

TERM	DEFINITION
401(k)	Progress Energy 401(k) Savings and Stock Ownership Plan
AFUDC	Allowance for funds used during construction
the Agreement	Stipulation and Settlement Agreement related to PEF retail rate matters
AHI	Affordable housing investment
APB No. 25	Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees"
ARO	Asset retirement obligation
Annual Average Price	Average wellhead price per barrel for unregulated domestic crude oil for the year
BART	Best Available Retrofit Technology
Base Rate Settlement	Settlement reached with the FPSC on September 7, 2005 on PEF's base rate proceeding
Bcf	Billion cubic feet
Broad River	Broad River LLC's Broad River Facility
Brunswick	Brunswick Nuclear Plant
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CO_2	Carbon dioxide
Caronet	Caronet, Inc.
CCO	Competitive Commercial Operations business included within the Progress Ventures segment, previously reported as a separate business segment
CERCLA or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Clean Smokestacks Act	North Carolina Clean Smokestacks Act enacted in June 2002
Coal and Synthetic Fuel	Business segment primarily comprised of synthetic fuel production and sales operations, the operation of synthetic fuel facilities for third-parties, coal terminal services, and fuel transportation and delivery operations
the Code	Internal Revenue Code
CO_2	Carbon dioxide
COL	Combined license
Colona	Colona Synfuel Limited Partnership, LLLP
Corporate	Collectively, the Parent, PESC and consolidation entities
Corporate and Other	Corporate and Other segment includes Corporate as well as other nonregulated business areas
CR3	Crystal River Unit No. 3 Nuclear Plant
CVO	Contingent value obligation
DIG Issue C20	FASB Derivatives Implementation Group Issue C20, "Interpretation of the meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature"
DOE	United States Department of Energy
Earthco	Four wholly owned coal-based solid synthetic fuel limited liability companies
ECRC	Environmental Cost Recovery Clause
EIA	Energy Information Agency
EITF	Emerging Issues Task Force
EITF 03-1	Emerging Issues Task Force No. 03-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments"
EITF 03-4	Emerging Issues Task Force No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash Balance' Pension Plan"

EMCs	Electric Membership Cooperatives
ENCNG	Eastern North Carolina Natural Gas Company, formerly referred to as EasternNC
Energy Delivery	Distribution operations of the Utilities
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPIK	EPIK Communications, Inc.
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environment and Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company
FIN No. 45	FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"
FIN No. 46R	FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51"
FIN No. 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143"
Florida Global Case	U.S. Global LLC v. Progress Energy, Inc. et al
Florida Progress or FPC	Florida Progress Corporation, one of our wholly owned subsidiaries
FPSC	Florida Public Service Commission
Fuels	Previously reported business segment that included natural gas, coal terminal and synthetic fuel operations
Funding Corp.	Florida Progress Funding Corporation, a wholly owned subsidiary of Florida Progress
GAAP	Accounting principles generally accepted in the United States of America
Gas	Natural gas drilling and production operations included within the Progress Ventures segment
Genco	Progress Genco Ventures LLC
Georgia Power	Georgia Power Company
Georgia Region	Reporting unit consisting of our Effingham, Monroe, Walton and Washington nonregulated generation plants in service
Global	U.S. Global LLC
Gulfstream	Gulfstream Gas System, L.L.C.
Harris	Shearon Harris Nuclear Plant
IBEW	International Brotherhood of Electrical Workers
IRS	Internal Revenue Service
Jackson	Jackson Electric Membership Corporation
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt-hour
Level 3	Level 3 Communications, Inc.
LIBOR	London Inter Bank Offering Rate
MACT	Maximum Achievable Control Technology
MDC	Maximum Dependable Capability
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MGP	Manufactured Gas Plant
MW	Megawatt
MWh	Megawatt-hour
Moody's	Moody's Investors Service, Inc.
NAAQS	National Ambient Air Quality Standards
NCNG	North Carolina Natural Gas Corporation
NSR	New Source Review requirement by EPA
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited

the Notes Guarantee	Florida Progress' full and unconditional guarantee of the Subordinated Notes
Nox	Nitrogen Oxide
Nox SIP Call	EPA rule which requires 22 states including North and South Carolina (but excluding Florida) to further reduce nitrogen oxide emissions.
NRC	United States Nuclear Regulatory Commission
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other comprehensive income as defined by GAAP
O&M	Operation and maintenance expense
Odyssey	Odyssey Telecorp, Inc.
OPEB	Postretirement benefits other than pensions
Order 2000	FERC order regarding RTOs which sets minimum characteristics and functions that RTOs must meet, including independent transmission service
P11	Intercession City Unit P11
the Parent	Progress Energy, Inc. holding company on an unconsolidated basis
PEC	Progress Energy Carolinas, Inc., formerly referred to as Carolina Power & Light Company
PEF	Progress Energy Florida, Inc., formerly referred to as Florida Power Corporation
PESC	Progress Energy Service Company, LLC
the Phase-out Price	Price per barrel of unregulated domestic crude oil at which Section 29/45K tax credits are fully eliminated
Power Agency	North Carolina Eastern Municipal Power Agency
Preferred Securities	7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A issued by the Trust
Preferred Securities Guarantee	Florida Progress' guarantee of all distributions related to the Preferred Securities
Progress Energy	Progress Energy, Inc. and subsidiaries on a consolidated basis
Progress Registrants	The individual reporting registrants within the Progress Energy consolidated group. Collectively, Progress Energy, Inc., PEC and PEF
Progress Fuels	Progress Fuels Corporation, formerly Electric Fuels Corporation
Progress Rail	Progress Rail Services Corporation
Progress Ventures	Business segment primarily comprised of nonregulated energy generation and marketing activities and natural gas operations
PRP	Potentially responsible party, as defined in CERCLA
PSSP	Performance Share Sub-Plan
PTC	Progress Telecommunications Corporation
PT LLC	Progress Telecom, LLC
PUHCA	Public Utility Holding Company Act of 1935, as amended
PURPA	Public Utilities Regulatory Policies Act of 1978
PVI	Progress Energy Ventures, Inc. (formerly referred to as Progress Ventures, Inc.)
PWC	Public Works Commission of the City of Fayetteville, North Carolina
PWR	Pressurized water reactor
QF	Qualifying facility
Rail Services	Previously reported business segment that included rail operations
RBCA or Global RBCA	Risk-based corrective action
RCA	Revolving credit agreement
Rockport	Indiana Michigan Power Company's Rockport Unit No. 2
Robinson	Robinson Nuclear Plant
ROE	Return on equity
RSA	Restricted stock awards program
RTO	Regional transmission organization
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
Section 29	Section 29 of the Internal Revenue Service Code
Section 29/45K	General business tax credits earned after December 31, 2005 for synthetic fuel

	production activities in accordance with Section 29
Section 45K	General business tax credit
(See Note/s "#")	For all sections, this is a reference to the Combined Notes to the Financial Statements contained in Part II, ITEM 8
S&P	Standard & Poor's Rating Services
SFAS	Statement of Financial Accounting Standards
SFAS No. 5	Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies"
SFAS No. 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 87	Statement of Financial Accounting Standards No. 87, "Employers' Accounting for Pensions"
SFAS No. 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes"
SFAS No. 115	Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities."
SFAS No. 123	Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation"
SFAS No. 123R	Statement of Financial Accounting Standards No. 123R, "Accounting for Stock-Based Compensation"
SFAS No. 131	Statement of Financial Accounting Standards No. 131, "Disclosures about Segments of an Enterprise and Related Information"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative and Hedging Activities"
SFAS No. 138	Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133"
SFAS No. 142	Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets"
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"
SFAS No. 149	Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"
SFAS No. 150	Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"
SNG	Southern Natural Gas Company
SO_2	Sulfur dioxide
SRS	Strategic Resource Solutions Corp.
Subordinated Notes	7.10% Junior Subordinated Deferrable Interest Notes due 2039 issued by Funding Corp.
Tax Agreement	Intercompany Income Tax Allocation Agreement
the Threshold Price	Price per barrel of unregulated domestic crude oil at which Section 29/45K tax credits begin to be reduced
the Trust	FPC Capital I, a wholly owned subsidiary of Florida Progress
the Utilities	Collectively, PEC and PEF
Winchester Production	Winchester Production Company, Ltd., an indirectly owned subsidiary of Progress Fuels Corporation
Winter Park	City of Winter Park, Florida

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

In this combined report, each of the Progress Registrants makes forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The matters discussed throughout this combined 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, but are not limited to, 1) statements made in PART I, ITEM 1A, “Risk Factors” and 2) PART II, ITEM 7, “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 2008 and future financing plans; c) “Strategy” about our future strategy and goals; and d) “Other Matters” about our synthetic fuel facilities, the effects of new environmental regulations, 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 the Progress Registrants undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

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

These and other risk factors are detailed from time to time in the Progress Registrants’ 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 ITEM 1A, “Risk Factors,” which you should carefully read. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the effect of each such factor on the Progress Registrants.

PART I

ITEM 1. BUSINESS

GENERAL

ORGANIZATION

Progress Energy, Inc., headquartered in Raleigh, N.C., with its regulated and nonregulated subsidiaries, is an integrated energy company serving the southeast region of the United States. In this report, Progress Energy (which includes Progress Energy, Inc.'s holding company operations (the Parent) and its subsidiaries on a consolidated basis), is at times referred to as "we," "our" or "us." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. However, neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

The Parent was initially incorporated on August 19, 1999 as CP&L Energy, Inc., which became the holding company for PEC on June 19, 2000. All shares of common stock of PEC were exchanged for an equal number of shares of CP&L Energy, Inc. common stock. On November 30, 2000, we completed our acquisition of Florida Progress Corporation (Florida Progress or FPC), a diversified, exempt electric utility holding company whose primary subsidiaries are PEF and Progress Fuels Corporation (Progress Fuels). In the $5.4 billion purchase transaction, we paid cash consideration of approximately $3.5 billion and issued 46.5 million shares of common stock valued at approximately $1.9 billion. In addition, we issued 98.6 million contingent value obligations (CVOs) valued at approximately $49 million. Prior to February 8, 2006, the Parent was a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Effective February 8, 2006, the Parent is subject to additional regulation by the Federal Energy Regulatory Commission (FERC) as discussed below.

Our wholly owned regulated subsidiaries, PEC and PEF, each a business segment, are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. We have over 21,500 megawatts (MW) of regulated electric generation capacity and serve approximately 3 million retail electric customers in portions of North Carolina, South Carolina and Florida as well as other load-serving entities. The Utilities operate in retail service territories that are anticipated to have population growth higher than the U.S. average. In addition, PEC's greater proportion of commercial and industrial customers, combined with PEF's greater proportion of residential customers, creates a balanced customer base. We are dedicated to expanding our electric generation capacity and delivering reliable, competitively priced energy from a diverse portfolio of power plants. Prior to December 2005, our reportable business segments included the PEC Electric segment that was comprised of PEC's utility operations and excluded immaterial operations of PEC's nonregulated subsidiaries that were previously included in our Corporate and Other segment. Management has realigned the PEC segment based on the manner in which these operations are reviewed to include PEC's nonregulated subsidiaries. The results of operations and financial position of PEC Electric and PEC are not materially different. Prior year periods have been restated for the PEC segment realignment.

During 2005, we also realigned our nonregulated business segments due to changes in the operations of certain businesses as discussed below and the reclassification of our coal mining operations as discontinued operations. This realignment is consistent with the manner in which management currently reviews these operations. Our current nonregulated segments are: 1) Progress Ventures and 2) Coal and Synthetic Fuels.

Our Progress Ventures segment is involved in nonregulated electric generation operations and energy marketing activities through our Competitive Commercial Operations business (CCO) and natural gas drilling and production (Gas). The functional management and financial reporting structure of the Progress Ventures business unit is not currently aligned with its legal structure. Prior to December 2005, Gas was included within our previously reported Fuels segment. We have historically disclosed CCO as a reportable segment. In the past several years, we have increased our natural gas reserves and our gas drilling capital to act as a natural hedge for CCO's nonregulated generation needs. Our CCO business underwent a significant change in 2005 with the expiration of its tolling agreements (which had little fuel price risk) at the end of 2004 and the increased load served under its fixed price full requirements contracts (which have substantial fuel price risk) effective in early 2005. Managing the operations of Gas and CCO on a combined basis allows us to more effectively manage our fuel price risk. Our Progress Ventures segment is involved in limited energy and commodity economic hedging activities and CCO will manage Gas' financial hedging operations. Prior year periods have been restated for the Progress Ventures segment realignment.

Our Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuel as defined under the Internal Revenue Code (the Code), the operation of synthetic fuel facilities for outside parties as well as coal terminal services and fuel transportation and delivery. Our Coal terminal operations support our Synthetic Fuel operations for the procuring and processing of coal and the transloading and marketing of synthetic fuel. Prior to 2005, all Coal operations (including mining), synthetic fuel activities and fuel transportation operations were included within our previously reported Fuels segment. Our coal mining business was reclassified as discontinued operations during 2005 as a result of our decision to divest of our coal mine assets. The remaining portions of the previously reported Fuels segment are included within Coal and Synthetic Fuels due to their operational relationship with the segment's activities and their relative immateriality. Prior year periods have been restated for the Coal and Synthetic Fuels segment realignment.

Prior to its divestiture in 2005, Rail Services was reported as a separate segment.

The Corporate and Other segment primarily includes the activities of the Parent, Progress Energy Service Company, LLC (PESC) and miscellaneous nonregulated businesses. PESC provides centralized administrative, management and support services to our subsidiaries. See Note 19 for additional information about PESC services provided and costs allocated to subsidiaries.

See Note 20 for information regarding the revenues, income and assets attributable to our business segments.

Our consolidated revenues for the year ended December 31, 2005, were $10.1 billion and our consolidated assets at year-end were $27.0 billion.

SIGNIFICANT DEVELOPMENTS

PROGRESS TELECOM DIVESTITURE

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

COAL MINE DIVESTITURE

On November 14, 2005, our board of directors approved a plan to divest of the five subsidiaries of Progress Fuels engaged in the coal mining business. The coal mining operations are expected to be sold by the end of 2006. As a result, we have classified the coal mining operations as discontinued operations in the accompanying consolidated financial statements for all periods presented (See Note 3A).

ACQUISITION BY WINCHESTER PRODUCTION COMPANY

In May 2005, Winchester Production Company, Ltd. (Winchester Production), an indirectly owned subsidiary of Progress Fuels, acquired a 50 percent interest in approximately 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million (See Note 4A).

PROGRESS RAIL DIVESTITURE

In March 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail). Gross cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. Proceeds from the sale were used to reduce debt (See Note 3B).

RAILCAR LTD., DIVESTITURE

In March 2003, we 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 3B).

NCNG DIVESTITURE

In September 2003, we completed the sale of North Carolina Natural Gas Corporation (NCNG) and our equity investment in Eastern North Carolina Natural Gas Company (ENCNG) to Piedmont Natural Gas Company, Inc. As a result of this action, the operating results of NCNG were reclassified to discontinued operations for all reportable periods. Net proceeds from the sale of NCNG and ENCNG of approximately $443 million were used to reduce debt (See Note 3H).

See Notes 3 and 4 for additional information about our acquisitions and divestitures.

AVAILABLE INFORMATION

The Progress Registrants' annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available free of charge through the Investors section of our internet site, http://www.progress-energy.com. These reports are available as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. The public may read and copy any material we have filed with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information regarding the operations of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. Alternatively, the SEC maintains an internet site, http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

The Investors section of our website also includes our corporate governance guidelines and code of ethics as well as the charters of the following committees of our board of directors: Audit and Corporate Performance; Corporate Governance; Finance; Operations, Environmental, Health and Safety Issues; and Organization and Compensation. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, Progress Energy, Inc., 410 S. Wilmington Street, Raleigh, NC 27601.

Information on our website is not incorporated herein and should not be deemed part of this Report.

COMPETITION

GENERAL

Over the past several years, the electric utility industry has experienced a substantial increase in competition at the wholesale level, caused by changes in federal law and regulatory policy. Several states have also restructured aspects of retail electric service. The issue of retail restructuring and competition is being reviewed by a number of states, and bills have been introduced in past sessions of Congress that sought to introduce such restructuring in all states.

On August 8, 2005, the Energy Policy Act of 2005 (EPACT) was signed into law. This new federal law contains key provisions affecting the electric power industry. These provisions include tax changes for the utility industry; incentives for emissions reductions; federal insurance and incentives to build new nuclear power plants; repeal of PUHCA, effective February 8, 2006; and certain protection for native retail load customers of load-serving entities.

It gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce greenhouse gases and redesignates the Code's Section 29 (Section 29) tax credit as a general business credit under the Code's Section 45K (Section 45K). See Note 23D for additional information on the redesignation of the Section 29 tax credits. In addition, the law requires both the FERC and the U.S. Department of Energy (DOE) to study how utilities dispatch their resources to meet the needs of their customers. The results of these studies or any related actions taken by DOE could impact the Utilities' system operations.

The law requires the FERC to issue certain regulations implementing EPACT within 120 days of enactment. The FERC has commenced the rulemaking process on 11 major issues and a number of secondary issues. We have reviewed the proposed rules and are participating in the public comment process. However, we cannot currently predict what impact the final rules will have on our financial condition and results of operations. The FERC has adopted final rules implementing its new authority under EPACT with regard to mergers, dispositions of utility assets, market manipulation, electric reliability organizations and PUHCA repeal. These new rules: require the FERC's approval prior to any merger involving a public utility; require the FERC's approval prior to the disposition of any utility asset with a market value in excess of $10 million; require utility holding companies to comply with the FERC's cost allocation, record retention and accounting rules; prohibit market participants from intentionally or recklessly making any fraudulent or misleading statements with regard to transactions subject to the FERC's jurisdiction; and establish the procedure and rules for the establishment of an electric reliability organization that will propose and enforce mandatory reliability standards for the bulk power electric system.

In November 2003, and as subsequently revised and supplemented, the FERC adopted standards of conduct that apply uniformly to interstate natural gas pipelines and public utilities and govern the relationship between transmission providers and their energy affiliates in a manner that prevents a transmission provider from unduly discriminating against nonaffiliates and from granting affiliates preferential treatment. Each utility was required to submit a plan and schedule for compliance with the new rules by February 2004. During 2005, following an audit by the FERC of the Utilities' compliance with the FERC's standards of conduct and the Utilities' codes of conduct, the Utilities reached a settlement with the FERC in regards to certain violations cited in the audit's results. Pursuant to the settlement, the Utilities agreed to make certain operational and organization changes and provided an immaterial monetary settlement in the form of a one-time credit to their retail and wholesale customers.

REGULATED UTILITIES

To date, many states have adopted legislation that would give retail customers the right to choose their electricity provider (retail choice), and most other states have, in some form, considered the issue. To our knowledge, there is currently no proposed legislation in North Carolina, South Carolina or Florida that would introduce retail choice.

ELECTRIC INDUSTRY RESTRUCTURING

The Utilities monitor developments impacting their competitive environments and actively participate in regulatory reform deliberations in their respective service territories. PEC expects that both the North Carolina and South Carolina General Assemblies will continue to monitor the experiences of states that have implemented electric restructuring legislation. PEF believes that the movement toward deregulation in Florida has been slowed by developments related to deregulation of the electric industry in other states.

REGIONAL TRANSMISSION ORGANIZATIONS

In October 2000, as a result of FERC Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of a regional transmission organization (RTO), GridSouth. In July 2001, the FERC issued an order provisionally approving GridSouth. However, in July 2001, the FERC issued orders recommending that companies in the southeast engage in mediation to develop a plan for a single RTO for the Southeast. PEC participated in the mediation. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding. PEC has $33 million invested in GridSouth related to startup costs at December 31, 2005. PEC expects to recover these startup costs.

Also as a result of FERC Order 2000, PEF, Florida Power & Light Company and Tampa Electric Company 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 Florida Public Service Commission (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. On December 12, 2005, the final report of the cost-benefit study was issued. The study concluded that the GridFlorida RTO was not cost effective. The study further segregated the costs and benefits between FPSC jurisdictional and nonjurisdictional customers, concluding that the jurisdictional customers would incur even more costs and benefits would be shifted to nonjurisdictional customers. In light of the findings and conclusions of the cost-benefit study, on January 27, 2006, the GridFlorida applicants filed a motion with the FPSC to withdraw the compliance filing and filed a petition to close the docketed proceeding. The Florida Municipal Power Agency and Seminole Electric Power Cooperative have submitted a filing in opposition to this motion. The FPSC has released a schedule that indicates that they will issue an order on this motion by April 24, 2006. The GridFlorida applicants are currently in discussions to determine whether there are cost-effective alternatives to the GridFlorida proposal that could be implemented in peninsular Florida. 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 PEF's earnings, revenues or pricing. PEF has fully recovered its startup costs in GridFlorida.

See Note 7C for further discussion regarding RTOs.

FRANCHISE MATTERS

PEC has nonexclusive franchises with varying expiration dates in most of the municipalities in which it distributes electric energy in North Carolina and South Carolina. The general effect of these franchises is to provide for the manner in which PEC occupies rights-of-way in incorporated areas of municipalities for the purpose of constructing, operating and maintaining an energy transmission and distribution system. Of these 239 franchises, 194 have expiration dates ranging from 2008 to 2061 and 45 of these have no specific expiration dates. All but 13 of the 194 franchises with expiration dates have a term of 60 years. The exceptions have terms ranging from 10 to 50 years. PEC also provides service within a number of municipalities and in all of its unincorporated areas without franchise agreements.

PEF holds franchises with varying expiration dates in 109 of the municipalities in which it distributes electric energy. PEF also provides service to 12 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. One city which had an expiring franchise agreement with PEF elected in 2005 to purchase the electric distribution system that served that city after satisfying regulatory and operating requirements (See Note 7C). Other litigation regarding franchise matters with certain Florida municipalities were largely resolved during 2005 with renewals of franchise agreements. The franchise agreements cover periods ranging from 10 to 30 years with the majority covering 30-year periods from the date enacted. Of the 109 franchise agreements, 3 expire between January 1, 2006 and December 31, 2010, and 106 expire between January 1, 2011 and December 31, 2035.

WHOLESALE COMPETITION

As a result of various changes in federal law and regulations over the past 25 years, there is competition in the wholesale electricity market. In 1996, the FERC issued new rules on transmission service requiring all utility transmission providers to provide transmission access and service to all market participants pursuant to standardized tariffs. The rules give greater flexibility and more choices to wholesale power customers. EPACT clarified and expanded the FERC's authority to assure that markets operate fairly without imposing new, mandatory intrusion on state authorities.

The increased competition in the wholesale electric utility industry and the availability of transmission access could affect the Utilities' load forecasts, plans for power supply and wholesale energy sales and related revenues. The impact could vary depending on the extent to which additional generation is built to compete in the wholesale market, new opportunities are created for the Utilities to expand their wholesale load, or current wholesale customers elect to purchase from other suppliers after existing contracts expire.

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

On June 6, 2005, the Utilities submitted market power studies to the FERC demonstrating that neither company possessed market power outside of peninsular Florida and PEC's control area. The FERC accepted the Utilities' respective market power studies and allowed PEC and PEF to continue selling power at market-based rates in areas outside of peninsular Florida and PEC's control area.

We do not anticipate that the current operations of the Utilities will be materially impacted by the market-based rates decision outlined above.

STRANDED COSTS

An issue encompassed by industry restructuring is the recovery of "stranded costs." Stranded costs primarily include the generation assets of utilities whose value in a competitive marketplace would be less than their current book value, as well as above-market purchased power commitments to qualifying facilities (QFs). Thus far, all states that have passed restructuring legislation have provided for the opportunity to recover a substantial portion of stranded costs. Assessing the amount of stranded costs for a utility requires various assumptions about future market conditions, including the future price of electricity.

The largest stranded cost exposure for PEF is its commitment to QFs. However, the FPSC allows for full recovery of the retail portion of QFs costs from customers. PEF continues to seek ways to address the impact of escalating payments from contracts it was obligated to sign under provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA).

EPACT repeals the mandatory purchase and sales requirements of PURPA in competitive markets as determined by the FERC. The law also requires the FERC to revise the criteria for new QFs and removes the ownership limitations on QFs.

NONREGULATED BUSINESSES

Progress Ventures' CCO operations are in the nonregulated wholesale market, which means competition is its primary driver. CCO competes in the eastern United States utility markets. Factors contributing to success in these markets include a competitive cost structure and strategic locations.

Progress Ventures' Gas operations develop and produce from wells located in Texas and Louisiana and sell at competitive prices throughout the region. Factors contributing to success include a competitive cost structure, the ability to execute the drilling plan and increase proven reserves.

Coal and Synthetic Fuel operations compete in the eastern United States steam and industrial coal markets. Factors contributing to 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.

REGULATORY MATTERS

PUHCA

As a result of the acquisition of Florida Progress, Progress Energy was a registered holding company subject to regulation by the SEC under PUHCA. Therefore, Progress Energy and its subsidiaries were subject to the regulatory provisions of PUHCA, including provisions relating to the issuance of securities, sales, acquisitions of securities and utility assets, and services performed by PESC.

As discussed under "COMPETITION – General", federal legislation was enacted during 2005 to repeal PUHCA effective February 8, 2006. Subsequent to that date, the Parent is no longer subject to regulation by the SEC as a public utility holding company. EPACT grants the FERC certain new powers including approval authority of mergers affecting utilities, disposition of utility assets with a value in excess of $10 million and accounting, record retention and cost allocation authority.

UTILITY REGULATION

PEC is subject to regulation in North Carolina by the North Carolina Utilities Commission (NCUC), and in South Carolina by the Public Service Commission of South Carolina (SCPSC) and PEF is subject to regulation in Florida by the FPSC with respect to, among other things, rates and service for electric energy sold at retail, retail service territory cost recovery of unusual or unexpected expense, such as severe storm costs, and issuances of securities. The Utilities are also subject to regulation by the United States Nuclear Regulatory Commission (NRC). In addition, the Utilities are 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 invested capital, including equity. Increased competition as a result of industry restructuring may affect the ratemaking process.

On February 7, 2006, the FPSC approved a utility pole inspection policy that requires extensive testing of wooden utility poles every eight years in an effort to reduce outages during severe storms. PEF does not anticipate a significant impact on its operations from complying with the new regulation as it already had a policy of inspecting its poles every 10 years, and some more often.

RETAIL RATE MATTERS

The NCUC, SCPSC and FPSC authorize retail "base rates" that are designed to provide the respective utility with the opportunity to earn a specific rate of return on its "rate base," or investment in utility plant. These rates are intended to cover all reasonable and prudent expenses of utility operations except those covered by specific cost recovery clauses and to provide investors with a fair rate of return.

In PEC's most recent rate cases in 1988, the NCUC and the SCPSC each authorized a return on equity of 12.75% for PEC. The Clean Smokestacks Act enacted in North Carolina in 2002 (Clean Smokestacks Act) froze PEC's base retail rates in North Carolina through December 31, 2007, unless there are extraordinary events beyond the control of PEC, in which case PEC can petition for a rate increase.

During 2005, the FPSC approved a four-year base rate agreement with PEF (Base Rate Settlement). The new base rates took effect the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009 with PEF having sole option to extend through the last billing cycle of June 2010. Base rates will be adjusted in late 2007 depending on the in-service date of specified generation facilities. The Base Rate Settlement also provides for revenue sharing between PEF and its customers. In 2006, PEF will refund two-thirds of retail, base revenues between the $1.499 billion threshold and the $1.549 billion cap and 100 percent of revenues above the $1.549 billion cap. Both the threshold and cap will be adjusted annually for rolling average 10-year retail kilowatt-hour (kWh) sales growth.

RETAIL COST RECOVERY CLAUSES

Each state utility commission allows recovery of certain costs through various cost recovery clauses, to the extent the respective commission determines in an annual hearing that such costs are prudent. Each state utility commission's 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. The Utilities do not make any profit on the recovery of such costs. Certain fuel costs are eligible for recovery by the Utilities. The Utilities use coal, oil, hydroelectric (PEC only), natural gas and nuclear power to generate electricity thereby maintaining a diverse fuel mix which helps mitigate the impact of cost increases in any one fuel. The Utilities make every effort to minimize these costs. Unless a commission finds a portion of such costs to have been imprudently incurred, 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 of the Utilities. However, delays between the expenditure for fuel costs and recovery from ratepayers can adversely impact the cash flow of the Utilities.

Costs recovered by the Utilities through cost recovery clauses, by retail jurisdiction, are as follows:

- *North Carolina Retail* – fuel costs and the fuel portion of purchased power
- *South Carolina Retail* – fuel costs, certain purchased power costs, and sulfur dioxide (SO_2) emission allowance expense
- *Florida Retail* – fuel costs, purchased power costs, capacity costs, energy conservation expense and specified environmental costs, including SO_2 emission allowance expense.

WHOLESALE RATE MATTERS

PEC and PEF are subject to regulation by the FERC with respect to rates for transmission and sale of electric energy at wholesale, the interconnection of facilities in interstate commerce (other than interconnections for use in the event of certain emergency situations), the licensing and operation of hydroelectric projects (PEC only) and, to the extent the FERC determines, accounting policies and practices. PEC and its wholesale customers last agreed to a general increase in wholesale rates in 1988 and PEF and its wholesale customers last agreed to a general increase in wholesale rates in 1995. However, wholesale rates for both of the Utilities have been adjusted since that time through contractual negotiations.

STORM RECOVERY

In accordance with a regulatory order, PEF accrues $6 million annually in base rates 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.

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes that impacted PEF's service territory in 2004. The initial impact was included in customer bills beginning August 1, 2005. The amount approved for recovery was based on PEF's estimate of costs. On September 12, 2005, PEF filed a true-up of an additional $19 million in costs. The increase was partially offset by $6 million of adjustments. The FPSC administratively approved the true-up amount, subject to audit by the FPSC staff. The net true-up effect was included in customer bills beginning January 1, 2006.

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

PEC does not maintain a storm damage reserve account and does not have an on-going regulatory mechanism to recover storm costs. In the past, PEC has sought and received permission from the SCPSC and NCUC to defer and amortize certain storm recovery costs.

See Note 7 for further discussion of regulatory matters.

NUCLEAR MATTERS

GENERAL

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.

PEC owns and operates four nuclear generating units, Brunswick Nuclear Plant (Brunswick) Unit No. 1 and Unit No. 2, Shearon Harris Nuclear Plant (Harris), and Robinson Nuclear Plant (Robinson). NRC operating licenses for Brunswick No. 1 and No. 2, Harris, and Robinson currently expire in September 2016, December 2014, October 2026, and July 2030, respectively. An application to extend the Brunswick licenses 20 years was submitted in October 2004. An application to extend the Harris license 20 years is expected to be submitted in the fourth quarter of 2006.

PEF owns and operates one nuclear generating unit, Crystal River Unit No. 3 (CR3). The NRC operating license 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.

Since 2001, PEC and PEF have made various modifications to increase the output of their nuclear facilities. The cumulative increase is approximately 315 MW, of which 311 MW is at PEC and 4 MW is at PEF.

We currently estimate that we will need to increase our baseload capacity in Florida and North and South Carolina by the middle of the next decade and are evaluating our options for future baseload generation needs. Both nuclear and coal technologies are being explored in parallel paths. We have announced that we are pursuing development of Combined License (COL) applications. Our announcement is not a commitment to build a nuclear plant. It is a necessary step to keep open the option of building a potential plant or plants. On January 23, 2006, we announced that PEC has selected the Harris site to evaluate for possible future nuclear expansion and we announced the selection of the Westinghouse Electric AP-1000 reactor design as the technology upon which to base the potential application submission. We currently expect to file the application for the COL for PEC's Harris site in late September or early October 2007. We expect to file the application for the COL for an as-yet unspecified site in Florida in late 2007 or first quarter 2008. We plan to announce the selection of the Florida site in spring 2006. If we receive approval from the NRC, and if the decision to build is made, construction could begin as early as 2010, and a new plant could be online around 2016. We estimate that it will take approximately 36 months for the NRC to review the COL applications and grant approval. See ITEM 1A, "Risk Factors" for additional information.

Our nuclear generating units are regulated by the 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 NRC periodically issues bulletins and orders addressing industry issues of interest or concern that necessitate a response from the industry. It is our intent to comply with and to complete required responses in a timely and accurate manner. Any potential impact to company operations will vary and will be dependent upon the nature of the requirement(s).

Since 2002, the NRC has issued various bulletins and orders addressing inspection activities associated with

Pressurized Water Reactor (PWR) vessels. We have complied with all requests. Additionally, we replaced the reactor vessel head at CR3 in 2003 and at Robinson in 2005.

SECURITY

The NRC has issued various orders since September 2001 with regard to security at nuclear plants. These orders include additional restrictions on access, increased security measures at nuclear facilities and closer coordination with our partners in intelligence, military, law enforcement and emergency response at the federal, state and local levels. We completed the requirements as outlined in the orders by the committed dates. As the NRC, other governmental entities and the industry continue to consider security issues, it is possible that more extensive security plans could be required.

SPENT FUEL AND OTHER HIGH-LEVEL RADIOACTIVE WASTE

The Nuclear Waste Policy Act of 1982 (Nuclear Waste Act) provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The Nuclear Waste Act promotes increased usage of interim storage of spent nuclear fuel at existing nuclear plants. We will continue to maximize the use of spent fuel storage capability within our own facilities for as long as feasible.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at Robinson, Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on their respective systems through the expiration of the operating licenses, including any license extensions, for all of their nuclear generating units. On March 30, 2005, the NRC issued a 40-year renewal for Robinson's Independent Spent Fuel Storage Installation license, which was due to expire in August 2006.

See Note 23D for a discussion of the Utilities' contracts with the DOE for spent nuclear waste.

DECOMMISSIONING AND DECONTAMINATION

In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC, the SCPSC and the FPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdiction, the provisions for nuclear decommissioning costs are approved by the FERC. A condition of the operating license for each unit requires an approved plan for decontamination and decommissioning. See Note 5D for a discussion of the Utilities' nuclear decommissioning costs.

ENVIRONMENTAL

In the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes and other environmental matters, we are subject to regulation by various federal, state and local authorities. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations constantly change and the ultimate costs of compliance cannot always be accurately estimated. The current estimated capital costs associated with compliance with pollution control laws and regulations that we expect to incur are included in the "Capital Expenditures" discussion for Progress Energy under PART II, ITEM 7, "Liquidity and Capital Resources."

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of legislation. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation.

There are presently several sites, including 11 manufactured gas plant (MGP) sites, with respect to which we have been notified by the EPA, the State of North Carolina or the State of Florida of our potential liability, as a potentially responsible party (PRP). We have accrued costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. Although we may incur additional costs at the sites about which we have been notified, based upon the current status of these sites, the total costs that may be incurred in connection with all sites cannot be determined at this time. It is probable that additional losses, which could be material, may be incurred in the future.

See Note 22 for additional discussion of our environmental matters, which identifies specific environmental issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

EMPLOYEES

As of February 15, 2006, we employed approximately 11,600 full-time employees. Of this total, approximately 2,000 employees at PEF are represented by the International Brotherhood of Electrical Workers (IBEW). The three-year labor contract with the IBEW expired in November 2005. In January 2006, we reached an agreement on a new three-year contract, which has been ratified by union members and is retroactive to November 2005.

We have a noncontributory defined benefit retirement (pension) plan for substantially all full-time employees and an employee stock purchase plan among other employee benefits. We also provide contributory postretirement benefits, including certain health care and life insurance benefits, for substantially all retired employees.

As of February 15, 2006, PEC and PEF employed approximately 5,000 and 3,700 full-time employees, respectively.

ELECTRIC – PEC

GENERAL

PEC is a public service corporation formed under the laws of North Carolina in 1926 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North and South Carolina. At December 31, 2005, PEC had a total summer generating capacity (including jointly owned capacity) of approximately 12,519 MW. For additional information about PEC's generating plants, see ELECTRIC – PEC in ITEM 2. PROPERTIES. PEC's system normally experiences its highest peak demands during the summer, and the all-time system peak of 12,577 megawatt-hour (MWh) was set on July 27, 2005.

PEC distributes and sells electricity in North Carolina and northeastern South Carolina. The service territory covers approximately 34,000 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. At December 31, 2005, PEC was providing electric services, retail and wholesale, to approximately 1.4 million customers. Major wholesale power sales customers include North Carolina Eastern Municipal Power Agency (Power Agency), North Carolina Electric Membership Corporation and Public Works Commission of the City of Fayetteville, North Carolina (PWC). PEC is subject to the rules and regulations of the FERC, the NCUC, the SCPSC and the NRC. No single customer accounts for more than 10% of PEC's revenues.

BILLED ELECTRIC REVENUES

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

BILLED ELECTRIC REVENUE PERCENTAGES

	2005	2004	2003
Residential	**37%**	38%	36%
Commercial	**24%**	25%	24%
Industrial	**18%**	19%	18%
Wholesale	**19%**	16%	20%
Other retail	**2%**	2%	2%

Major industries in PEC's service area include textiles, chemicals, metals, paper, food, rubber and plastics, wood products and electronic machinery and equipment.

FUEL AND PURCHASED POWER

SOURCES OF GENERATION

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

ENERGY MIX PERCENTAGES

	2005	2004	2003
Coal	**47%**	47%	46%
Nuclear	**42%**	43%	44%
Purchased power	**6%**	6%	7%
Oil/Gas	**4%**	3%	2%
Hydro	**1%**	1%	1%

PEC is generally permitted to pass the cost of fuel and certain purchased power costs 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" and ITEM 1A, "Risk Factors." However, PEC believes that its fuel supply contracts, as described below, will be adequate to meet its fuel supply needs.

PEC's average fuel costs per million British thermal units (Btu) for the last three years were as follows:

AVERAGE FUEL COST

(per million Btu)	**2005**	2004	2003
Coal	**$ 2.72**	$ 2.17	$ 2.00
Nuclear	**0.42**	0.42	0.43
Oil	**8.60**	6.78	6.69
Gas	**10.90**	8.29	8.32
Weighted-average	**2.03**	1.57	1.43

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

PEC anticipates a requirement of approximately 12.8 million to 13.4 million tons of coal in 2006. Almost all of the coal will be supplied from Appalachian coal sources in the United States and is primarily delivered by rail.

For 2006, PEC has short-term, intermediate and long-term agreements from various sources for approximately 107% of its estimated burn requirements of its coal units. Amounts in excess of PEC's estimated burn requirements will be used to build up inventory levels or be consumed if the burn requirements increased above forecast. All of these contracts are at fixed prices adjusted annually. The contracts have expiration dates ranging from 2006 to 2010. PEC will continue to sign contracts of various lengths, terms and quality to meet its expected burn requirements. All the coal to be purchased for PEC is considered to be low-sulfur coal by industry standards.

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.

PEC has sufficient uranium, conversion, enrichment and fabrication contracts to meet its near-term nuclear fuel requirement needs. PEC's nuclear fuel contracts typically have terms ranging from five to ten years. For a discussion of PEC's plans with respect to spent fuel storage, see PART I, ITEM 1, "Nuclear Matters."

Oil and Gas

Oil and natural gas supply for PEC's generation fleet is purchased under term and spot contracts from several suppliers. PEC has dual-fuel generating facilities that can operate with both oil and gas. The cost of PEC's oil and gas is determined by market prices as reported in certain industry publications. PEC believes that it has access to an adequate supply of oil and gas for the reasonably foreseeable future. PEC's natural gas transportation for its baseload gas generation is purchased under term firm transportation contracts with interstate pipelines. PEC also purchases capacity on a seasonal basis from numerous shippers for its peaking load requirements. PEC believes that existing contracts for oil are sufficient to cover its requirements if natural gas is unavailable during a normal winter period for PEC's combustion turbine and combined cycle fleet.

Hydroelectric

PEC has three hydroelectric generating plants licensed by the FERC: Walters, Tillery and Blewett. PEC also owns the Marshall Plant, which has a license exemption. The total maximum dependable capacity for all four units is 218 MW. PEC is seeking to relicense its Tillery and Blewett Plants. The license for these plants currently expires in April 2008. The Walters Plant license will expire in 2034.

Purchased Power

PEC purchased approximately 4.7 million MWh, 4.0 million MWh and 4.5 million MWh of its system energy requirements during 2005, 2004 and 2003 and had 1,518 MW of firm purchased capacity under contract during 2005. PEC may acquire additional purchased power capacity in the future to accommodate a portion of its system load needs and PEC believes that it can obtain enough purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

ELECTRIC – 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, 2005, PEF had a total summer generating capacity (including jointly owned capacity) of approximately 9,045 MW. For additional information about PEF's generating plants, see ELECTRIC – PEF in ITEM 2. PROPERTIES. PEF's system normally experiences its highest peak demands during the winter, and the all-time system peak of 10,131 MWh was set on January 24, 2003. PEF's system set a new summer peak demand of 9,406 MWh on August 16, 2005.

PEF distributes and sells electricity in Florida. The 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 22 municipal and 9 rural electric cooperative systems. At December 31, 2005, PEF was providing electric services, retail and wholesale, to approximately 1.6 million customers. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Florida Power & Light Company, Tampa Electric Company, and the cities of Bartow, Winter Park (Winter Park) and Tallahassee. PEF is subject to the rules and regulations of the FERC, the 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 REVENUE PERCENTAGES

	2005	2004	2003
Residential	**52%**	53%	55%
Commercial	**25%**	25%	24%
Industrial	**8%**	8%	7%
Wholesale	**9%**	8%	8%
Other retail	**6%**	6%	6%

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

SOURCES OF GENERATION

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 last three years is presented in the following table:

ENERGY MIX PERCENTAGES

	2005	2004	2003
Coal (a)	**33%**	32%	36%
Oil/Gas	**33%**	32%	29%
Nuclear	**13%**	16%	14%
Purchased Power	**21%**	20%	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” and ITEM 1A, “Risk Factors.” 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)	**2005**	2004	2003
Coal (a)	**$ 2.70**	$ 2.30	$ 2.42
Oil	**5.90**	4.67	4.38
Nuclear	**0.51**	0.49	0.50
Gas	**8.53**	6.41	5.98
Weighted-average	**4.15**	3.21	3.07

(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 2006. 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 water. All of this fuel has historically been supplied by Progress Fuels, a subsidiary of Progress Energy, pursuant to contracts between PEF and Progress Fuels. Beginning in 2006, PEF will enter into coal contracts on its own behalf.

For 2006, Progress Fuels has medium-term and long-term contracts with various sources for approximately 115% of the estimated burn requirements of PEF’s coal units. Amounts in excess of PEF’s estimated burn requirements will be used to build up inventory levels or be consumed if the burn requirements increased above forecast. These contracts have price adjustment provisions and have expiration dates ranging from 2006 to 2010. All the coal to be purchased for PEF is considered to be low-sulfur coal by industry standards.

Oil and Gas

Oil and natural gas supply for PEF’s generation fleet is purchased under term and spot contracts from several suppliers. PEF has dual-fuel generating facilities that can operate with both oil and gas. The majority of the cost of PEF’s oil and gas is either hedged at a fixed price or 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 for its gas generation is purchased under term firm transportation contracts with interstate pipelines. PEF purchases capacity on a seasonal basis from numerous shippers and interstate pipelines to serve its peaking load requirements. PEF also 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. 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 purchased approximately 9.9 million MWh, 9.4 million MWh and 9.4 million MWh of its system energy requirements during 2005, 2004 and 2003 and had 1,631 MW of firm purchased capacity under contract during 2005. These agreements include approximately 812 MW of capacity under contract with certain QFs. PEF may acquire additional purchased power capacity in the future to accommodate a portion of its system load needs and PEF believes that it can obtain enough purchased power to meet these needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected.

PROGRESS VENTURES

The Progress Ventures business segment is responsible for electric generation operations and energy marketing activities in the nonregulated wholesale market and natural gas drilling and production. CCO currently owns six electricity generation facilities with approximately 3,100 MW of generation capacity, and it has contractual rights to an additional 2,500 MW of generation capacity from mixed fuel generation facilities through its agreements with 16 Georgia electric membership cooperatives (EMCs). CCO has contracts for its combined production capacity of approximately 86% for 2006, approximately 81% for 2007, and approximately 84% for 2008. The Progress Ventures segment also includes natural gas properties in Texas and Louisiana producing approximately 24 billions of cubic feet (Bcf) equivalent per year.

The energy that CCO markets is sold under both term contracts and in the spot market. CCO purchases fuel, such as oil and natural gas, for use in the generation of electricity. We believe that there are adequate sources of fuel for CCO's expected fuel requirements. CCO also uses financial instruments to manage the risks associated with fluctuating commodity prices to hedge the economic value of its portfolio of assets. We strive to mitigate the risks associated with CCO's full-requirements supply contracts though various strategies including, but not limited to: having access to fixed price callable resources; having contractual caps on cooperative load growth; using selected power hedges over the terms of these agreements; using our generating assets to serve this load; and using our gas reserves in Texas and Louisiana as an economic hedge. However, we cannot provide certainty that these risk management techniques will be effective.

In May 2003, Progress Energy Ventures, Inc. (PVI) acquired from Williams Energy Marketing and Trading, a subsidiary of the Williams Companies, Inc., a long-term full-requirements power supply agreement at fixed prices with Jackson Electric Membership Corporation (Jackson), for $188 million. In 2004, PVI executed wholesale power-supply agreements with 15 Georgia EMCs to serve their electricity needs through 2010.

During 2005, we acquired approximately a 50 percent ownership interest in 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent ownership interest in the gas gathering systems related to these reserves. The total cash purchase price for the transactions was $46 million (See Note 4A).

In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production, a wholly owned subsidiary of Progress Fuels for net proceeds of approximately $251 million (See Note 3E).

During 2003, Progress Fuels acquired approximately 200 natural gas-producing wells with proven reserves of approximately 190 Bcf from Republic Energy, Inc. and three other privately owned companies, all headquartered in Texas. The total cash purchase price for the transactions was approximately $168 million (See Note 4C).

COAL AND SYNTHETIC FUEL

We have substantial operations associated with the production of coal-based solid synthetic fuels including five majority owned synthetic fuel entities and one minority interest in a synthetic fuel entity, capable of producing up to 16 million tons per year. The production and sale of these products qualifies for federal income tax credits within the meaning of Section 29/45K so long as certain requirements are satisfied. These operations are subject to numerous risks. We also have five terminals on the Ohio River and its tributaries which blend and transload coal and are part of the trucking, rail and barge network for coal delivery.

Through tax years 2005, our ability to utilize tax credits was dependent on having a sufficient tax liability. In 2005, the tax law was changed and this constraint no longer applies beginning in tax year 2006. Synthetic fuel is generally not economical to produce absent the credits. The tax credits associated with synthetic fuels may be phased out if market prices for crude oil exceed certain prices.

Our synthetic fuel operations and related risks are described in more detail in Note 23D and in ITEM 1A, “Risk Factors.”

On November 14, 2005, our board of directors approved a plan to divest of the five subsidiaries of Progress Fuels engaged in the coal mining business. The coal mining operations are expected to be sold by the end of 2006. As a result, we have classified the coal mining operations as discontinued operations in the accompanying consolidated financial statements for all periods presented (See Note 3A).

CORPORATE AND OTHER

GENERAL

The Corporate and Other business segment includes the operations of PT LLC, Strategic Resource Solutions Corp. (SRS) and the Parent as well as other nonregulated operations.

PT LLC

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 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 held a 55% ownership interest in, and was the parent of, PT LLC; Odyssey held a combined 45% ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Consolidated Financial Statements since the transaction date.

PT LLC has data fiber network transport capabilities that stretch from New York to Miami 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, 2005, PT LLC owned and managed more than 8,524 route miles of fiber and 29 metro networks.

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

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

ELECTRIC UTILITY REGULATED OPERATING STATISTICS – PROGRESS ENERGY

	Years Ended December 31				
	2005	2004	2003	2002	2001
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**52,306**	50,782	51,501	49,734	48,732
Nuclear	**30,120**	30,445	30,576	30,126	27,301
Combustion Turbines/Combined Cycle	**11,349**	9,695	7,819	8,522	6,644
Hydro	**749**	802	955	491	245
Purchased	**14,566**	13,466	13,848	14,305	14,469
Total energy supply (Company share)	**109,090**	105,190	104,699	103,178	97,391
Jointly owned share (a)	**5,388**	5,395	5,213	5,258	4,886
Total system energy supply	**114,478**	110,585	109,912	108,436	102,277
Average fuel cost (per million Btu)					
Fossil	**$4.05**	$3.17	$2.94	$2.62	$2.46
Nuclear fuel	**$0.44**	$0.44	$0.44	$0.44	$0.45
All fuels	**$2.83**	$2.21	$2.05	$1.84	$1.77
Energy sales (millions of kilowatt-hours)					
Retail					
Residential	**36,558**	35,350	34,712	33,993	31,976
Commercial	**25,258**	24,753	24,110	23,888	23,033
Industrial	**16,856**	17,105	16,749	16,924	17,204
Other Retail	**4,608**	4,475	4,382	4,287	4,149
Wholesale	**21,137**	18,323	19,841	19,204	17,715
Unbilled	**(440)**	449	189	275	(1,045)
Total energy sales	**103,977**	100,455	99,983	98,571	93,032
Company uses and losses	**5,113**	4,735	4,716	4,607	4,359
Total energy requirements	**109,090**	105,190	104,699	103,178	97,391
Electric revenues (in millions)					
Retail	**$ 6,607**	$ 6,066	$ 5,620	$ 5,515	$ 5,462
Wholesale	**1,103**	843	914	881	923
Miscellaneous revenue	**235**	244	207	205	172
Total electric revenues	**$ 7,945**	$ 7,153	$ 6,741	$ 6,601	$ 6,557

(a) Amounts represent co-owners' share of the energy supplied from the six generating facilities that are jointly owned.

REGULATED OPERATING STATISTICS – PEC

	Years Ended December 31				
	2005	2004	2003	2002	2001
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**29,780**	28,632	28,522	28,547	27,913
Nuclear	**24,291**	23,742	24,537	23,425	21,321
Combustion Turbines/Combined Cycle	**2,475**	1,926	1,344	1,934	802
Hydro	**749**	802	955	491	245
Purchased	**4,656**	4,023	4,467	5,213	5,296
Total energy supply (Company share)	**61,951**	59,125	59,825	59,610	55,577
Power Agency share (a)	**4,857**	4,794	4,670	4,659	4,348
Total system energy supply	**66,808**	63,919	64,495	64,269	59,925
Average fuel cost (per million Btu)					
Fossil	**$3.30**	$2.52	$2.29	$2,16	$1.91
Nuclear fuel	**$0.42**	$0.42	$0.43	$0.43	$0.44
All fuels	**$2.03**	$1.57	$1.43	$1.38	$1.26
Energy sales (millions of kilowatt-hours)					
Retail					
Residential	**16,664**	16,003	15,283	15,239	14,372
Commercial	**13,313**	13,019	12,557	12,468	11,972
Industrial	**12,716**	13,036	12,749	13,089	13,332
Other Retail	**1,410**	1,431	1,408	1,437	1,423
Wholesale	**15,673**	13,222	15,518	15,024	12,996
Unbilled	**(235)**	91	(44)	270	(534)
Total energy sales	**59,541**	56,802	57,471	57,527	53,561
Company uses and losses	**2,410**	2,323	2,354	2,083	2,016
Total energy requirements	**61,951**	59,125	59,825	59,610	55,577
Electric revenues (in millions)					
Retail	**$ 3,133**	$ 2,953	$ 2,824	$ 2,796	$ 2,666
Wholesale	**759**	575	687	651	634
Miscellaneous revenue	**98**	100	78	92	44
Total electric revenues	**$ 3,990**	$ 3,628	$ 3,589	$ 3,539	$ 3,344

(a) Amounts represent Power Agency's share of the energy supplied from the four generating facilities that are jointly owned.

REGULATED OPERATING STATISTICS – PEF

	Years Ended December 31				
	2005	2004	2003	2002	2001
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**22,526**	22,150	22,979	21,187	20,819
Nuclear	**5,829**	6,703	6,039	6,701	5,980
Combustion Turbines/Combined Cycle	**8,874**	7,769	6,475	6,588	5,842
Purchased	**9,910**	9,443	9,381	9,092	9,173
Total energy supply (Company share)	**47,139**	46,065	44,874	43,568	41,814
Jointly owned share (a)	**531**	601	543	599	538
Total system energy supply	**47,670**	46,666	45,417	44,167	42,352
Average fuel cost (per million Btu)					
Fossil	**$4.88**	$3.86	$3.63	$3.15	$3.09
Nuclear fuel	**$0.51**	$0.49	$0.50	$0.46	$0.47
All fuels	**$4.15**	$3.21	$3.07	$2.60	$2.59
Energy sales (millions of kilowatt-hours)					
Retail					
Residential	**19,894**	19,347	19,429	18,754	17,604
Commercial	**11,945**	11,734	11,553	11,420	11,061
Industrial	**4,140**	4,069	4,000	3,835	3,872
Other Retail	**3,198**	3,044	2,974	2,850	2,726
Wholesale	**5,464**	5,101	4,323	4,180	4,719
Unbilled	**(205)**	358	233	5	(511)
Total energy sales	**44,436**	43,653	42,512	41,044	39,471
Company uses and losses	**2,703**	2,412	2,362	2,524	2,343
Total energy requirements	**47,139**	46,065	44,874	43,568	41,814
Electric revenues (in millions)					
Retail	**$ 3,474**	$ 3,113	$ 2,796	$ 2,719	$ 2,796
Wholesale	**344**	268	227	230	289
Miscellaneous revenue	**137**	144	129	113	128
Total electric revenues	**$ 3,955**	$ 3,525	$ 3,152	$ 3,062	$ 3,213

(a) Amounts represent co-owners' share of the energy supplied from the two generating facilities that are jointly owned.

ITEM 1A. RISK FACTORS

Investing in the securities of the Progress Registrants involves risks, including the risks described below, that could affect the Progress Registrants and their businesses, as well as the energy industry generally. Most of the business information as well as the financial and operational data contained in our risk factors are updated periodically in the reports the Progress Registrants file with the SEC. Although the Progress Registrants have tried to discuss key risk factors, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and the Progress Registrants cannot predict such risks or estimate the extent to which they may affect their financial performance. Before purchasing securities of the Progress Registrants, you should carefully consider the following risks and the other information in this combined Annual Report, as well as the documents the Progress Registrants file with the SEC from time to time. Each of the risks described below could result in a decrease in the value of the securities of the Progress Registrants and your investment therein.

Solely with respect to this ITEM 1A, "Risk Factors" unless the context otherwise requires or the disclosure otherwise indicates, references to "we," "us" or "our" are to each of the individual Progress Registrants and the matters discussed are generally applicable to each Progress Registrant.

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, the Utilities are subject to federal 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.

On August 8, 2005, the EPACT was signed into law. This new federal law contains key provisions affecting the electric power industry. These provisions include tax changes for the utility industry, incentives for emissions reductions, federal insurance and incentives to build new nuclear power plants, repeal of PUHCA effective February 8, 2006, and certain protections for native retail load customers of utilities with an obligation to serve. It gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce greenhouse gases and redesignates the Section 29 tax credit as a Section 45K general business credit. See Note 23D for additional information on the redesignation of the Section 29 tax credits. In addition, the law requires both the FERC and the DOE to study how utilities dispatch their resources to meet the needs of their customers. The results of these studies or any related actions taken by DOE could impact the Utilities' system operations.

The law requires the FERC to issue certain regulations implementing EPACT within 120 days of enactment. The FERC has commenced the rulemaking process and it is ongoing. We have reviewed the proposed rules and are participating in the public comment process. The FERC has issued a final rule regarding mergers and disposition of utility assets which requires FERC approval of: the sale or disposition of wholesale power contracts, or transmission or existing generation facilities with a value in excess of $10 million; the merger or consolidation of any or all of a public utility's facilities with any other person; and the purchase or acquisition of any securities with a value in excess of $10 million of any other public utility. The FERC's new rule implementing its new responsibilities resulting from the repeal of PUHCA provides that going forward, holding companies with an interest in a public utility must comply with the FERC's document retention and accounting rules, maintain and make available to the FERC their books and records that are relevant to the public utility's costs, and account for costs incurred by a public utility as a result of an affiliate transaction pursuant to the FERC's policies. We cannot currently predict what impact issuance of the remaining final rules, or the interpretation and implementation of any new rules, will have on our business operations, financial condition and results of operations.

In response to rising fuel costs and the extensive hurricane-related power outages and costs experienced in the past two years in Florida, there is currently considerable discussion about energy issues at both the FPSC and Florida legislature. However, the outcome of these matters on PEF cannot be predicted.

The FERC, the NRC, the EPA, the NCUC, the FPSC, and the SCPSC regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. 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 production, handling and disposal. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant operations. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, authorizations 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 adjudication or litigation that may arise.

In addition, we may be deemed a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount or timing of 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.

There are proposals to address global climate change that would regulate carbon dioxide (CO_2) and other greenhouse gases. Any future regulatory actions taken to address global climate change represent a business risk to our operations. In 2005, we initiated a study to assess the impact of constraints on CO_2 and other air emissions. We plan to issue this report by March 31, 2006.

We have articulated principles that we believe should be incorporated into any global climate change policy. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act.

Our compliance with environmental regulations requires significant capital expenditures that impact our financial condition. Under Florida law, these expenditures are eligible for recovery outside of base rates under an environmental cost recovery clause. There is no comparable treatment of these types of expenditures under North Carolina or South Carolina law. Clean air regulations require reduction of emissions of nitrogen oxide (NOx), SO_2 and mercury from coal-fired power plants. We expect the future capital expenditures required to meet the emission limits, a portion of which are eligible for regulatory recovery, will be in excess of $1.0 billion each at PEC and PEF, respectively, through 2018, which corresponds to the latest emission reduction deadline. However, these costs could be higher than currently expected and have an adverse impact on our results of operations and financial condition.

The operation of emission control equipment to meet the emission limits will increase our operating costs and could reduce the generating capacity of our coal-fired plants. Operation and maintenance costs will significantly increase due to the additional personnel, materials and general maintenance associated with the equipment. The emission control equipment will require the procurement of significant quantities of limestone and ammonia. Future increases in demand for these items from other utility companies operating the same equipment could increase the costs associated with operating the equipment.

For additional discussion of environmental matters, see Note 22.

We cannot provide assurance 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.

Because weather conditions directly influence the demand for and cost of providing electricity, our results of operations, financial condition, cash flows and ability to pay dividends on our common stock 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 territories, primarily North Carolina, South Carolina, Georgia, and Florida, directly influence the demand for electricity and 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 summer months. In other areas, power demand peaks during the winter months. 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 mild. While we believe that our North Carolina, South Carolina, Georgia, and Florida markets complement each other during normal seasonal fluctuations, 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 resulting in lost operating revenues, incurring property damage, downing power lines and requiring us to incur additional and unexpected expenses.

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.

We are subject to incurring significant costs resulting from severe weather. While PEF was granted regulatory approval in 2005 to recover significant storm costs incurred in 2004 for the four hurricanes that impacted our service territory, PEC's and PEF's storm cost recovery petitions may not always be granted.

Under a regulatory order, PEF maintains a storm damage reserve account for major storms. Due to the significant costs incurred to recover from the 2004 hurricanes, PEF's storm damage reserve accounts were largely depleted at December 31, 2005. PEF is currently considering alternatives for replenishing its storm damage reserve account such as issuing securitized bonds or otherwise seeking replenishment from retail ratepayers. Storm reserve costs attributable to wholesale customers may be amortized consistent with recovery of such amounts in wholesale rates, albeit at a specified amount per year resulting in an extended recovery period.

PEC does not maintain a storm damage reserve account and does not have an on-going regulatory mechanism to recover storm costs. PEC has previously sought and received permission from the NCUC and the SCPSC to defer storm expenses and amortize them over five-year periods. PEC did not seek deferral of storm costs from the NCUC or SCPSC during 2005.

If we cannot recover costs associated with future significant weather events in a timely manner, or in an amount sufficient to cover our actual costs, or if our storm reserve is inadequate, 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, 2005, commercial and industrial customers represented approximately 42% and 33% of PEC's and PEF's billed electric revenues, respectively. 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. In recent years, in North and South Carolina, sales to industrial customers have been affected by downturns in the textile and chemical industries.

For the year ended December 31, 2005, 19% and 9% of PEC's and PEF's billed electric revenues, respectively, 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 and market conditions.

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two new interim screens for assessing potential generation market power of applicants for wholesale market-based rates, and described additional analyses and mitigation measures that could be presented if an applicant does not pass one of these interim screens. In July 2004, the FERC issued a second order that affirmed its April order and initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. PEC and PEF do not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believed it would experience in passing one of the interim screens, on September 6, 2005, PEC filed revisions to its market-based rate tariffs restricting PEC's authority to sell power in the wholesale market at market-based rates to areas outside of PEC's control area and peninsular Florida, and a new cost-based tariff for sales within PEC's control area consistent with the FERC's default cost-based rate methodologies for sales of one year or less. The FERC has accepted these revisions. Although we cannot predict the ultimate outcome of these changes, we do not anticipate that the current operations of the Utilities will be materially impacted by their inability to sell power at market-based rates in their respective control areas.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs. Increased competition may also result from power industry consolidation. Increased competition could adversely affect the financial condition, results of operations or cash flows of us and our utilities' businesses.

Increased competition resulting from deregulation or restructuring efforts or from industry consolidation could have a significant adverse financial impact on us and consequently, on our results of operations and cash flows. Increased competition could 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. Several significant mergers and acquisitions in the power industry were announced during 2005. We may experience increased competition in our nonregulated businesses as we compete with larger entities that may have more capital and financial resources and are able to leverage their economies of scale. Furthermore, if we decide to expand operations, we may encounter significant competition for future acquisition opportunities.

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 North Carolina, South Carolina and 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 our ownership of energy-related assets. Energy commodity price fluctuations impact PEC and PEF as well as our nonregulated businesses. While each state commission allows electric utilities to recover certain of these costs through various cost recovery clauses, there is the potential that a portion of 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 and when these costs are recovered from the ratepayers, which can adversely impact the cash flow of the Utilities. In addition, the under-recovery of fuel costs can also negatively impact our interest expense and leverage and rising fuel costs can also lead to higher electric utility rates which can negatively impact customer satisfaction.

Our nonregulated energy businesses also purchase fuel commodities to fulfill their operating needs. Some of their wholesale power supply contracts are at fixed prices; consequently, higher commodity prices could result in decreased margins.

Volatility in market prices for fuel and power may result from:

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, terrorism, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

Prices for SO_2 emission allowance credits under the EPA's emission trading program increased significantly during 2005. While SO_2 allowances are eligible for annual recovery in PEF's jurisdictions in Florida and PEC's in South Carolina, no such annual recovery exists in North Carolina for PEC. Future increases in the price of SO_2 allowances could have a significant adverse financial impact on us and PEC and consequently, on our results of operations and cash flows.

As a holding company with no operations, the Parent is dependent on upstream cash flows from its subsidiaries, primarily our regulated utilities. As a result, our ability to meet our ongoing and future debt service and other financial obligations and to pay dividends on our common stock is primarily dependent on the earnings and cash flows of our operating subsidiaries and their ability to pay upstream dividends or to repay funds to us.

The Parent is a holding company and as such, has no operations of its own. The Parent's ability to meet its financial obligations associated with the debt service obligations on $4.3 billion of holding company debt and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay upstream dividends or to repay funds to the Parent. Prior to funding the Parent, its subsidiaries have financial obligations that must be satisfied, including among others, their respective debt service, preferred dividends and obligations to trade creditors. For the year ending December 31, 2005, the Utilities generated approximately 100 percent of consolidated cash from operations. Other sources of cash include the issuance of equity, short-term and long-term debt, asset sales and intercompany charges for capital costs.

The rates that PEC and PEF 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 do not control operating and capital investment costs.

The NCUC, the SCPSC and the FPSC each exercises regulatory authority for review and approval of the retail electric power rates charged within its respective state. State regulators may not allow PEC and PEF to increase retail rates in the manner or to the extent requested by those subsidiaries. State regulators may also seek to reduce or freeze retail rates.

Both PEC and PEF currently operate under rate freezes, in which rates can only be changed under certain circumstances. The costs incurred by PEC and PEF are generally not subject to being fixed or reduced by state regulators. There is a risk that the Utilities' results of operations could be negatively impacted if the Utilities do not manage their costs effectively. Our ability to maintain our profit margins depends upon stable demand for electricity and our efforts to manage our costs.

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.

PEC (four units; 3,485 MW) and PEF (one unit; 838 MW) own and operate five nuclear units that collectively represent approximately 4,323 MW, or 20%, of our regulated generation capacity for the year ended December 31, 2005. Our nuclear facilities are 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 decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks. However, it is possible that damages from an accident or business interruption at our nuclear units 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 noncompliance, 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.

Meeting the anticipated growth in our service territories requires a balanced solution that includes energy conservation and efficiency programs, development and deployment of new technologies and the potential need to increase our baseload generation within the next decade. Increasing our generation capacity could involve the construction of new generation facilities, including nuclear, for which we would have to comply with a significant number of federal and state regulations. There are uncertainties that we will be able to obtain needed licenses for construction of new generation facilities or successfully and timely complete their construction. In addition, there are uncertainties that the cost of new generation facilities and new programs will be recoverable through our base rates.

We are currently evaluating our options for future baseload generation needs. Both nuclear and coal technologies are being explored in parallel paths. At this time, no definitive decision has been made regarding the construction of either nuclear or coal plants, or both. Additional capacity needs may be displaced by purchased power agreements, cogeneration contract extensions or other sources based on on-going economic and non-economic evaluations.

If we decide to construct new generation facilities or expand existing facilities, there is no assurance that we will be able to successfully and timely complete the projects. Should any such efforts be unsuccessful, we could be subject to additional costs and/or the write-off of our investment in the project or improvement. Furthermore, we have no assurance that costs incurred to construct or expand generation facilities will be recoverable through our base rates.

The decision to build a baseload power plant will be based on several factors including power market conditions, competing fuel prices, the regulatory environment, the status of permanent used nuclear fuel storage and the ability to obtain financing. The construction of a new baseload plant will require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support the construction. Additionally, any borrowings incurred to finance the construction expenditures may adversely impact our leverage and our results of operations.

The construction of a new nuclear power plant requires a number of conditions to be successful. The conditions include, but are not limited to: the continued operation of the industries' existing nuclear fleet in a safe, reliable, and cost-effective manner; the use of standardized plants and an efficient licensing process; the ability to raise capital on reasonable terms; a viable program for managing spent nuclear fuel; and both public and policymaker support. We cannot provide certainty that these conditions will exist.

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

One consideration that would improve the economics of the nuclear option is whether the plant will be eligible for the federal production tax credits and risk insurance provided for by EPACT. EPACT provides for an annual tax credit of 1.8 cents/kilowatt hour (kWh) for nuclear facilities for the first eight years of operation. However, the credit is limited to the first 6,000 MW of new nuclear generation in the United States and has an annual cap of $125 million per unit. The credit allocation process among new nuclear plants has not been determined. There are other utilities that have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant constructed by us would qualify for these additional incentives. Failure to qualify for these incentives could significantly impact the economics of building a nuclear facility.

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

Our financial performance depends on the successful operation of electric generating facilities by our subsidiaries 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, pandemic health events such as avian influenza 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, 2005, commercial paper and bank borrowings and long-term debt balances were as follows (in millions):

Company	Outstanding Commercial Paper	Total Long-Term Debt, Net
Progress Energy, unconsolidated (a)	$ –	$ 3,874
PEC	73	3,667
PEF	102	2,554
Other subsidiaries (b)	–	351
Progress Energy, consolidated (c)	$ 175	$ 10,446

(a) Represents solely the outstanding indebtedness of the Parent.
(b) Includes the following subsidiaries: Florida Progress Funding Corporation ($270 million) and Progress Capital Holdings, Inc. ($81 million).
(c) Net of current portion, which at December 31, 2005, was $513 million on a consolidated basis.

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

At December 31, 2005, we had an aggregate of three committed revolving credit agreements (RCAs) that supported our commercial paper programs totaling $2.030 billion. While our internal financial policy precludes us from issuing commercial paper in excess of our revolving credit lines, at December 31, 2005, we had $175 million reserved for outstanding commercial paper balance and a total of $150 million reserved for backing of letters of credit, leaving an additional $1.705 billion available for future borrowing under our revolving credit lines. At December 31, 2005, the actual amount of letters of credit issued was $33 million.

Our revolving credit lines impose various limitations that could impact our liquidity, such as defined maximum total debt to total capital (leverage) ratios and minimum coverage ratios. Under these revolving credit facilities, indebtedness includes certain letters of credit and guarantees which are not recorded on our consolidated Balance Sheets. At December 31, 2005, the required and actual ratios, pursuant to the terms of the credit agreements were as follows:

	Leverage Ratios		Coverage Ratios	
Company	Maximum Ratio	Actual Ratio (a)	Minimum Ratio	Actual Ratio
Progress Energy, Inc.	68%	60.7%	2.5:1	3.9:1
PEC	65%	55.2%	n/a	n/a
PEF	65%	50.9%	n/a	n/a

(a) Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees that are not recorded on the 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, Progress Energy, Inc.'s RCA includes a provision under which lenders could refuse to advance funds to us in the event of a material adverse change in our financial condition. Loan draws for the payment of maturing commercial paper are excluded from this provision. A limitation in our liquidity could have a material adverse impact on our business strategy and our ongoing financing needs.

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

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

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;
- impacting our ability to pay dividends on our common stock at the current rate;
- 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, Inc. (Moody's) announced that it lowered the ratings of PEF, Progress Capital Holdings, Inc. and FPC Capital Trust I and changed their rating outlooks to stable from negative. Moody's affirmed the ratings of Progress Energy and PEC. The rating outlooks continue to be stable at PEC and negative at Progress Energy. Moody's stated that it took this action primarily due to declining cash flow coverages and rising leverage, higher operation and maintenance (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 November 22, 2005, Standard & Poor's Rating Services (S&P) announced that it revised its ratings outlook on Progress Energy from negative to stable, affirming the BBB corporate credit rating, and revising the short-term rating from A-3 to A-2. As a result of this revision, PEC and PEF's outlooks and short-term ratings were also revised from negative to stable and A-3 to A-2, respectively. S&P stated that it took these actions primarily due to the resolution of several regulatory issues in Florida and expectations of increased likelihood that our financial performance will improve over the next two years. S&P also indicated that it has improved its business position for PEF to a '4' (strong). The business position for PEC remains a '5' (satisfactory) and the overall business position for Progress Energy remains at a '6' (satisfactory). S&P ranks business position on a scale of '1' (excellent) to '10' (vulnerable).

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

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

Our debt indentures and credit agreements do not contain any "ratings triggers," which would cause the acceleration of interest and principal payments in the event of a ratings downgrade. If S&P lowers Progress Energy's senior unsecured rating one ratings category to BB+ from its current rating, it would be a non-investment grade rating. The effect of a non-investment grade rating would primarily be increased borrowing costs.

While our long-term target credit ratings for each entity are above the minimum investment grade ranking, we cannot provide certainty that any of Progress Energy's current ratings, or those of PEC and PEF, 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. We note that the ratings from credit agencies are not recommendations to buy, sell or hold our securities or those of PEC or PEF and that each rating should be evaluated independently of any other rating.

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2005, we have issued $1.78 billion of guarantees for future financial or performance assurance. We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

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

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.

Additionally, we are exposed to risk that our counterparties will not be able to perform their obligations. Should our counterparties fail to perform, we might be forced to replace the underlying commitment at then-current market prices. In such event, we might incur losses in addition to the amounts, if any, already paid to the counterparties.

Our results of operations may be materially affected if the value of the Section 29/45K tax credits is reduced due to the high price of oil. This risk is not applicable to PEC and PEF.

Recent unprecedented and unanticipated increases in the price of oil could limit the amount of Section 29/45K 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 29/45K tax credits are reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. Although data for 2005 is not yet available, we do not expect the amount of our 2005 Section 29 tax credits to be adversely affected by crude oil prices. We cannot predict with any certainty the Annual Average Price for 2006 or beyond. Therefore, we cannot predict whether the price of oil will have a material effect on our synthetic fuel business after 2005. However, if during 2006 or 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. See Note 23D for additional information on the potential impact of crude oil prices on our synthetic fuel production.

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

A decrease in future synthetic fuel production and cash flows could trigger impairment evaluations of our synthetic fuel and other related operating long-lived assets. Such evaluations could result in an impairment charge for these assets which have total carrying values of approximately $111 million at December 31, 2005. The majority of these assets will be fully depreciated by the end of 2007, the scheduled end of the Section 29/45K tax credit program.

There are risks involved with the operation of our nonregulated plants, including dependence on third parties and related counter-party risks, and a lack of operating history, all of which may make our nonregulated generation and overall operations less profitable and more unstable.

At December 31, 2005, we had approximately 3,100 MW of nonregulated generation in commercial operation.

The operation of nonregulated generation facilities is subject to many risks, including those listed below. During the execution of our nonregulated generation strategy, these risks may intensify. These risks include:

- We may enter into or otherwise acquire long-term contracts that take effect at a future date based upon our future expected nonregulated generation capacity. If our generating facilities do not operate as expected, we may not be able to meet our obligations under any such long-term contracts and may have to purchase power in the spot market at then-prevailing prices. If we are unable to secure favorable pricing in the spot market, our results of operations could be negatively impacted. We may also become liable under any related performance guarantees then in existence.

- Our nonregulated generation facilities depend on third parties through power purchase agreements, fuel supply and transportation agreements and transmission grid connection agreements. If such third parties breach their obligations to us, our revenues, financial condition, cash flow and ability to make payments of interest and principal on our outstanding debts may be impaired. Any material breach by any of these parties of their obligations under the project contracts could adversely affect our cash flows.

- We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas that we sell to the wholesale market. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual obligations may be hindered. Although the FERC has issued regulations designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets.

- Agreements with our counterparties frequently will include the right to terminate and/or withhold payments or performance under the contracts if specific events occur. If a project contract were to be terminated due to nonperformance by us or by the other party to the contract, our ability to enter into a substitute agreement having substantially equivalent terms and conditions is uncertain.

- Operation of our facilities could be affected by many factors, including start-up problems, the breakdown or failure of equipment or processes, performance below expected levels of output or efficiency, failure to operate at design specifications, labor disputes, changes in law, failure to obtain necessary permits or to meet permit conditions, government exercise of eminent domain power or similar events and catastrophic events including fires, explosions, earthquakes and droughts.

- Our nonregulated generation facilities seek to enter into long-term power purchase agreements to sell all or a portion of their generating capacity. CCO currently owns six electricity generation facilities with approximately 3,100 MW of generation capacity, and it has contractual rights to an additional 2,500 MW of generation capacity from mixed fuel generation facilities through its agreements with 16 Georgia EMCs. CCO has contracts for its combined production capacity of approximately 86% for 2006, 81% for 2007 and 84% for 2008. The increased cooperative load in Georgia significantly increased CCO's revenue and cost of sales from 2004 to 2005 at lower margins, as more fully discussed below. Following the expiration or early termination of our power purchase agreements, or to the extent we cannot otherwise secure contracts for our current and future generation capacity, our facilities will generally become merchant facilities. Our merchant facilities may not be able to find adequate purchasers, attain favorable pricing, or otherwise compete effectively in the wholesale market. Additionally, numerous legal and regulatory limitations restrict our ability to operate a facility on a wholesale basis.

Our energy marketing and trading operations are subject to risks that could reduce our revenues and adversely impact our results of operations and financial condition; some of these risks, such as weather-related risks, are beyond our control. Volatile commodity prices could reduce our margins. Significant revenue reductions or cost increases could trigger future impairment evaluations and potential impairment charges.

We actively seek to manage the market risk inherent in our energy marketing operations. We employ best practices risk management monitoring and control techniques to manage the risks inherent in the business. Nonetheless, adverse changes in energy and fuel prices may result in losses in our earnings or cash flows and adversely affect our financial position. Our marketing and risk management procedures do not completely eliminate risk. As a result, our operating results and financial position are sensitive to the market risk factors discussed below.

Our fleet of nonregulated power plants sells energy into the spot market, other competitive power markets or on a longer-term contractual basis. We may also enter into contracts to purchase and sell electricity, natural gas and coal as part of our power marketing and energy trading operations. Our business may also include entering into tolling contracts, long-term contracts that supply customers' full electric requirements or other contractual structures. Over the past two years, we have entered into full requirements power contracts to supply the total power requirement of several electric cooperatives. These contracts do not provide a guaranteed rate of return on our capital investments through mandated rates. While these contracts are partially hedged through fixed price power and gas purchases, our revenues and results of operations from these contracts still depend to some degree upon prevailing market prices for power in our regional markets and surrounding competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Future adverse changes in market conditions or changes in business conditions could trigger future impairment evaluations of goodwill, long-lived assets or other assets, which could result in impairment charges.

In particular, we believe that over the past few years, the wholesale energy market in the southeastern United States, particularly Georgia, has been overbuilt and, accordingly, believe that the supply of peaking and mid-market generation exceeds demand. While recent market activity indicates that supply and demand are slowly coming closer to equilibrium, we believe that spot prices as well as contractual pricing will provide us with a reduced rate of return on our capital investment in our nonregulated plants and our revenues and results of operations from this market will be lower than originally expected until demand catches up with supply. We have no assurance that the current over-supply of wholesale power will be available to meet the Utilities' anticipated future need for additional baseload generation.

We have entered into wholesale power agreements with electric cooperatives in Georgia. Under these full-requirements supply contracts, we receive a fixed price for the power supplied to the cooperatives. The cooperative load is dependent on the weather and economy of its service area. We use a combination of callable resources from the cooperatives, open market purchases and our own generating assets to serve this load. The risks in serving full-requirements supply contracts at a fixed price include both the variability in commodity prices and the volatility of the cooperative energy demand. While we strive to mitigate the risks associated with these contracts though various strategies, we cannot provide certainty that our risk management techniques will be effective.

Furthermore, the FERC, which has jurisdiction over wholesale power rates, as well as independent system operators that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. As discussed previously, fuel prices also may be volatile, and the price we can obtain for power sales may not change at the same rate as our fuel costs changes. These factors could reduce our margins and therefore diminish our revenues and results of operations.

We actively manage the market risk inherent in our energy marketing operations. Nonetheless, adverse changes in energy and fuel prices may result in losses in our earnings or cash flows and adversely affect our balance sheet. Our marketing and risk management procedures may not work as planned. As a result, we cannot predict with precision the impact that our marketing, trading and risk management decisions may have on our business, operating results or financial position. In addition, to the extent that we do not cover the entire exposure of our assets or our positions to market price volatility, or our hedging procedures do not work as planned, fluctuating commodity prices could cause our sales and net income to be volatile.

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

Our nonregulated businesses are involved in operations that are subject to significant operational and financial risks that may reduce our revenues and adversely impact our results of operations and financial condition.

We are exposed to operational risk resulting from our natural gas drilling, coal mining, terminal and barge and fuel delivery operations. Our coal mining and natural gas drilling operations are subject to conditions beyond our control that can delay deliveries or increase the cost of mining or drilling at particular locations for varying lengths of time. Such conditions include unexpected maintenance problems, key equipment failures and variations in geologic conditions. The states in which we operate coal mines have state programs for mine safety and health regulation and enforcement. Financial risks include our 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

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

ELECTRIC – PEC

PEC's 18 generating plants represent a flexible mix of fossil, nuclear, hydroelectric, combustion turbines and combined cycle resources, with a total summer generating capacity of approximately 12,519 MW. Of this total, Power Agency owns approximately 700 MW. On December 31, 2005, PEC had the following generating facilities:

Facility	Location	No. of Units	In-Service Date	Fuel	PEC Ownership (in %)		Summer Net Capability (a) (in MW)	
STEAM TURBINES								
Asheville	Skyland, N.C.	2	1964-1971	Coal	100		392	
Cape Fear	Moncure, N.C.	2	1956-1958	Coal	100		316	
Lee	Goldsboro, N.C.	3	1952-1962	Coal	100		407	
Mayo	Roxboro, N.C.	1	1983	Coal	83.83		745	(b)
Robinson	Hartsville, S.C.	1	1960	Coal	100		174	
Roxboro	Roxboro, N.C.	4	1966-1980	Coal	96.32	(c)	2,462	(b)
Sutton	Wilmington, N.C.	3	1954-1972	Coal	100		613	
Weatherspoon	Lumberton, N.C.	3	1949-1952	Coal	100		176	
	Total	19					5,285	
COMBINED CYCLE								
Cape Fear	Moncure, N.C.	2	1969	Oil	100		84	
Richmond	Hamlet, N.C.	1	2002	Gas/Oil	100		472	
	Total	3					556	
COMBUSTION TURBINES								
Asheville	Skyland, N.C.	2	1999-2000	Gas/Oil	100		330	
Blewett	Lilesville, N.C.	4	1971	Oil	100		52	
Darlington	Hartsville, S.C.	13	1974-1997	Gas/Oil	100		812	
Lee	Goldsboro, N.C.	4	1968-1971	Oil	100		91	
Morehead City	Morehead City, N.C.	1	1968	Oil	100		15	
Richmond	Hamlet, N.C.	5	2001-2002	Gas/Oil	100		775	
Robinson	Hartsville, S.C.	1	1968	Gas/Oil	100		15	
Roxboro	Roxboro, N.C.	1	1968	Oil	100		15	
Sutton	Wilmington, N.C.	3	1968-1969	Gas/Oil	100		64	
Wayne County	Goldsboro, N.C.	4	2000	Gas/Oil	100		668	
Weatherspoon	Lumberton, N.C.	4	1970-1971	Gas/Oil	100		138	
	Total	42					2,975	
NUCLEAR								
Brunswick	Southport, N.C.	2	1975-1977	Uranium	81.67		1,875	(b)(d)
Harris	New Hill, N.C.	1	1987	Uranium	83.83		900	(b)
Robinson	Hartsville, S.C.	1	1971	Uranium	100		710	
	Total	4					3,485	
HYDRO								
Blewett	Lilesville, N.C.	6	1912	Water	100		22	
Marshall	Marshall, N.C.	2	1910	Water	100		5	
Tillery	Mount Gilead, N.C.	4	1928-1960	Water	100		86	
Walters	Waterville, N.C.	3	1930	Water	100		105	
	Total	15					218	
TOTAL		83					12,519	

(a) Amounts represent PEC's net summer peak rating, gross of co-ownership interest in plant capacity.
(b) Facilities are jointly owned by PEC and Power Agency. The capacities shown include Power Agency's share.
(c) PEC and Power Agency are co-owners of Unit 4 at the Roxboro Plant. PEC's ownership interest in this 700 MW unit is 87.06%.
(d) During 2005, a power uprate increased the net summer capability of Unit 2 to 937 MW. The Maximum Dependable Capability (MDC) was restated in January 2006.

At December 31, 2005, including both the total generating capacity of 12,519 MW and the total firm contracts for purchased power of approximately 1,518 MW, PEC had total capacity resources of approximately 14,037 MW.

Power Agency has undivided ownership interests of 18.33% in Brunswick Unit Nos. 1 and 2, 12.94% in Roxboro Unit No. 4 and 16.17% in Harris and Mayo Unit No. 1. Otherwise, PEC 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. PEC also owns certain easements over private property on which transmission and distribution lines are located.

At December 31, 2005, PEC had approximately 6,000 circuit miles of transmission lines including 300 miles of 500 kilovolt (kV) lines and 3,000 miles of 230 kV lines. PEC also had approximately 45,000 circuit miles of overhead distribution conductor and 19,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 12,500,000 kilovolt-ampere (kVA) in 2,406 transformers. Distribution line transformers numbered approximately 517,000 with an aggregate capacity of approximately 21,800,000 kVA.

ELECTRIC – PEF

PEF's 14 generating plants represent a flexible mix of fossil, nuclear, combustion turbine and combined cycle resources with a total summer generating capacity of approximately 9,045 MW. Of this total, joint owners own approximately 117 MW. At December 31, 2005, 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.	3	1999-2005	Gas/Oil	100	1,499
Tiger Bay	Fort Meade, Fla.	1	1997	Gas	100	207
	Total	4				1,706
COMBUSTION TURBINES						
Avon Park	Avon Park, Fla.	2	1968	Gas/Oil	100	52
Bartow	St. Petersburg, Fla.	4	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 (b)	1,041 (c)
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 (c)
	Total	1				838
TOTAL		64				9,045

(a) Amounts represent PEF's net summer peak rating, gross of co-ownership interest in plant capacity.
(b) PEF and Georgia Power Company (Georgia Power) are co-owners of a 143 MW advanced combustion turbine located at PEF's Intercession City site. 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.
(c) Facilities are jointly owned. The capacities shown include joint owners' share.

During 2005, PEF had total capacity resources of approximately 10,676 MW, including both the total generating capacity of 9,045 MW and the total firm contracts for purchased power of 1,631MW.

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 Unit P11 (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, 2005, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and about 1,500 miles of 230 kV lines. PEF also had approximately, 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 16,000,000 kVA in 682 transformers. Distribution line transformers numbered approximately 374,000 with an aggregate capacity of approximately 19,000,000 kVA.

COAL AND SYNTHETIC FUELS

The Coal and Synthetic Fuels business segment has an interest in six synthetic fuel entities. Five of the entities are majority owned and one is minority owned. These facilities are in six different locations in West Virginia and Kentucky.

Through our subsidiaries, we 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.

In connection with our coal operations, we own and operate surface and underground mines, coal processing and loadout facilities in southeastern Kentucky and southwestern Virginia. We control either directly or through our subsidiaries, demonstrated coal reserves located in eastern Kentucky and southwestern Virginia of approximately 47 million tons and control, through mineral leases, additional estimated coal reserves of approximately 58 million tons. The reserves controlled include substantial quantities of high quality, low-sulfur coal. Our total production of coal during 2005 was approximately 3.4 million tons. We employ both our own miners as well as contract miners in our mining activities.

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels engaged in the coal mining business. The coal mining operations are expected to be sold by the end of 2006. As a result, we have classified the coal mining operations as discontinued operations in the accompanying consolidated financial statements for all periods presented (See Note 3A).

PROGRESS VENTURES

At December 31, 2005, CCO had the following nonregulated generation plants in service.

Project	Location	Commercial Operation Date	Configuration/ Number of Units	MW (a)
Monroe Units 1 and 2	Monroe, Ga.	1999-2001	Simple Cycle, 2	315
Rowan Phase I	Salisbury, N.C.	2001	Simple Cycle, 3	459
Walton	Monroe, Ga.	2001	Simple Cycle, 3	460
DeSoto Units	Arcadia, Fla.	2002	Simple Cycle, 2	320
Effingham	Rincon, Ga.	2003	Combined Cycle, 1	480
Rowan Phase II	Salisbury, N.C.	2003	Combined Cycle, 1	466
Washington	Sandersville, Ga.	2003	Simple Cycle, 4	600
Total				3,100

(a) Amounts represent CCO's summer rating.

Our oil and gas production in 2005 was 24 Bcf equivalent. We have oil and gas leases in East Texas and Louisiana with total proven oil and gas reserves of approximately 325 Bcf equivalent.

CORPORATE AND OTHER

PT LLC provides wholesale telecommunications services throughout the Eastern United States. PT LLC incorporates more than 8,524 route miles of fiber and 29 metro networks, including more than 200 points-of-presence, or physical locations where a presence for network access exists.

On January 25, 2006, we signed a definitive agreement to sell PT LLC to Level 3 for a purchase price of approximately $137 million (See Note 25).

ITEM 3. LEGAL PROCEEDINGS

Legal proceedings are included in the discussion of our business in PART I, ITEM 1 under "Environmental," and are incorporated by reference herein. For a discussion of certain other legal matters, see Note 23D.

During 2005, we did not have any "reportable transactions" as defined under Section 6011 of the Code nor did we incur any penalties related to failing to report such information on our tax returns.

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

None

The information called for by ITEM 4 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

EXECUTIVE OFFICERS OF THE REGISTRANTS

Name	Age	Recent Business Experience
*Robert B. McGehee	62	**Chairman and Chief Executive Officer,** Progress Energy, May 2004 and March 2004, respectively, to present. Mr. McGehee joined Progress Energy (formerly Carolina Power & Light Company “CP&L”) in 1997 as Senior Vice President and General Counsel. Since that time, he has held several senior management positions of increasing responsibility. Most recently, Mr. McGehee served as President and Chief Operating Officer, having responsibility for the day-to-day operations of our regulated and nonregulated businesses. Prior to that, Mr. McGehee served as President and Chief Executive Officer of Progress Energy Service Company, LLC. Before joining Progress Energy, Mr. McGehee chaired the board of Wise Carter Child & Caraway, a law firm headquartered in Jackson, Miss. He primarily handled corporate, contract, nuclear regulatory and employment matters. During the 1990s, he also provided significant counsel to U.S. companies on reorganizations, business growth initiatives and preparing for deregulation and other industry changes.
William D. Johnson	52	**President and Chief Operating Officer,** Progress Energy, January 2005 to present; Group President, PEC, January 2004 to present; Executive Vice President and Corporate Secretary, PEC, PEF, Progress Energy Service Company, LLC and Florida Progress November 2000 to December 2003. Mr. Johnson has been with Progress Energy (formerly CP&L) since 1992 and served as Group President, Energy Delivery, Progress Energy, January 2004 to December 2004. Prior to that, he was President, CEO and Corporate Secretary, Progress Energy Service Company, LLC, October 2002 to December 2003. He also served as Executive Vice President – Corporate Relations & Administrative Services, General Counsel and Secretary of Progress Energy. Mr. Johnson served as Vice President – Legal Department and Corporate Secretary, CP&L from 1997 to 1999. Before joining Progress Energy, Johnson was a partner with the Raleigh office of Hunton & Williams, where he specialized in the representation of utilities.
Peter M. Scott III	56	**Executive Vice President and Chief Financial Officer,** Progress Energy, May 2000 to present; and May 2000 to December 2003 and November 2005 to present; **President and Chief Executive Officer,** Progress Energy Service Company, LLC, January 2004 to present; Executive Vice President, PEC and PEF, May 2000 to present and CFO of PEC, PEF, FPC and Progress Energy Service Company, LLC, 200 to 2003, and November 2005 to present. Mr. Scott has been with Progress Energy since May 2000. Before joining Progress Energy, Mr. Scott was the president of Scott, Madden & Associates, Inc., a general management consulting firm

headquartered in Raleigh that he founded in 1983. The firm served clients in a number of industries, including energy and telecommunications. Particular practice area specialties for Mr. Scott included strategic planning and operations management.

Jeffrey M. Stone	45	**Chief Accounting Officer and Controller,** Progress Energy and FPC, June 2005 to present; Chief Accounting Officer PEC and PEF, June 2005 to present; Vice President and Controller, Progress Energy Service Company, LLC, January 2005 and June 2005, respectively to present. Since 1999, Mr. Stone has served Progress Energy in a number of roles in corporate support including Vice President – Capital Planning and Control; Executive Director – Financial Planning & Regulatory Services, as well as in various management positions with Energy Supply and Audit Services. Prior to joining Progress Energy, Mr. Stone worked as an auditor with Deloitte & Touche in Charlotte, N.C.
Donald K. Davis	60	**Executive Vice President,** PEC, May 2000 to present; President, Progress Fuels Corporation, March 2005 to present. Mr. Davis is also President and Chief Executive Officer, SRS, June 2000 to present and was President and Chief Executive Officer, NCNG, July 2000 to September 2003. Mr. Davis joined Progress Energy in May 2000 as Executive Vice President, Gas and Energy Services. Before joining Progress Energy, Mr. Davis was Chairman, President and Chief Executive Officer of Yankee Atomic Electric Company, and served as Chairman, President and Chief Executive Officer of Connecticut Atomic Power Company from 1997 to May 2000 where he was responsible for two electric wholesale generating companies.
Fred N. Day IV	62	**President and Chief Executive Officer,** PEC, November 2003 to present; Executive Vice President, PEF, November 2000 to present. Mr. Day oversees all aspects of Carolinas Delivery operations, including distribution and customer service, transmission, and products and services. He previously served as Executive Vice President, PEC and PEF. During his more than 30 years with Progress Energy (formerly CP&L), Mr. Day has held several management positions of increasing responsibility. He was promoted to Vice President – Western Region in 1995.
*H. William Habermeyer, Jr.	63	**President and Chief Executive Officer,** PEF, November 2000 to present. Mr. Habermeyer joined Progress Energy (formerly PEC) in 1993 after a career in the U.S. Navy. During his tenure with Progress Energy, Mr. Habermeyer has served as Vice President – Nuclear Services and Environmental Support; Vice President – Nuclear Engineering; and Vice President – Western Region. While overseeing Western Region operations, Mr. Habermeyer was responsible for regional distribution management, customer support and community relations. In February 2006, Mr. Habermeyer announced that he will retire in May 2006.
C. S. Hinnant	61	**Senior Vice President and Chief Nuclear Officer**, PEC, June 1998 to present. Mr. Hinnant is also Senior Vice President and Chief Nuclear Officer, PEF, November 2000 and November 2005, respectively to present. Mr. Hinnant joined Progress Energy (formerly CP&L) in 1972 at the

		Brunswick Nuclear Plant near Southport, N.C., where he held several positions in the startup testing and operating organizations. He left Progress Energy in 1976 to work for Babcock and Wilcox in the Commercial Nuclear Power Division, returning to Progress Energy in 1977. Since that time, he has served in various management positions at three of Progress Energy's nuclear plant sites.
*Jeffrey J. Lyash	44	**Senior Vice President,** PEF, November 2003 to present. Mr. Lyash oversees all aspects of energy delivery operations for PEF. Prior to coming to PEF, Mr. Lyash was Vice President – Transmission in Energy Delivery in the Carolinas since January 2002. Mr. Lyash joined Progress Energy in 1993 and spent his first eight years at the Brunswick Nuclear Plant in Southport, N.C. His last position at Brunswick was as Director of site operations.
John R. McArthur	50	**Senior Vice President, General Counsel and Secretary** of Progress Energy, January 2004 to present. Mr. McArthur oversees the Audit Services, Corporate Communications, Legal, Regulatory and Corporate Relations – Florida, and State Public Affairs departments, and the Environmental and Health and Safety sections. Mr. McArthur is also Senior Vice President and Corporate Secretary, FPC and PEC, and Senior Vice President, PEF and Progress Energy Service Company, LLC, January 1 2004 and December 2002, respectively to present. Previously, he served as Senior Vice President – Corporate Relations (December 2002 to December 2003) and as Vice President – Public Affairs (December 2001 to December 2002). Before joining Progress Energy in December 2001, Mr. McArthur was a member of North Carolina Governor Mike Easley's senior management team, handling major policy initiatives as well as media and legal affairs. He also directed Governor Easley's transition team after the election of 2000. From November of 1997 until November of 2000, Mr. McArthur handled state government affairs in 10 southeastern states for General Electric Co. Prior to joining General Electric Co., Mr. McArthur served as chief counsel in the North Carolina Attorney General's office, where he supervised utility, consumer, health care, and environmental protection issues. Before that, he was a partner at Hunton & Williams.
E. Michael Williams	57	**Senior Vice President,** PEC and PEF, June 2000 and November 2000, respectively, to present. Before joining Progress Energy in 2000, Mr. Williams was with Central and Southwest Corp., Inc. and subsidiaries for 28 years and served in various positions prior to becoming Vice President – Fossil Generation in Dallas.
Lloyd M. Yates	45	**Senior Vice President,** PEC, January 2005 to present. Mr. Yates is responsible for managing the four regional vice presidents in the PEC organization. He served PEC as Vice President – Transmission from November 2003 to December 2004. Mr. Yates served as Vice President – Fossil Generation for PEC from 1998 to 2003. Before joining Progress Energy in 1998, Mr. Yates was with PECO Energy, where he had served in a number of engineering and management roles over 16 years. His last position with PECO was as general manager – Operations

in the power operations group.

*Mark F. Mulhern	46	**President,** Progress Energy Ventures, Inc., March 2005 to present. Mr. Mulhern is responsible for managing the Competitive Commercial Operations and Gas Operations groups of Progress Energy Ventures, Inc. He previously served Progress Energy Ventures, Inc. as Senior Vice President – Competitive Commercial Operations from January 2003 to March 2005. He served Progress Energy as Vice President – Strategic Planning from November 2000 to March 2003. He also served as Vice President and Treasurer of PEC from June 1997 to November 2000.

*Indicates individual is an executive officer of Progress Energy, Inc., but not PEC.

PART II

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

Progress Energy

Progress Energy's Common Stock is listed on the New York Stock Exchange under the symbol PGN. The high and low intra-day stock sales prices for each quarter for the past two years, and the dividends declared per share are as follows:

	High	Low	Dividends Declared
2005			
First Quarter	**$ 45.33**	**$ 40.63**	**$0.590**
Second Quarter	**45.83**	**40.61**	**0.590**
Third Quarter	**46.00**	**41.90**	**0.590**
Fourth Quarter	**45.50**	**40.19**	**0.605**
2004			
First Quarter	$ 47.95	$ 43.02	$0.575
Second Quarter	47.50	40.09	0.575
Third Quarter	44.32	40.76	0.575
Fourth Quarter	46.10	40.47	0.590

The December 31 closing price of our Common Stock was $43.92 for 2005 and $45.24 for 2004. As of February 28, 2006, we had 64,404 holders of record of Common Stock.

Neither Progress Energy's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends. Our subsidiaries have provisions restricting dividends in certain limited circumstances (See Notes 10A and 12B).

Issuer purchases of equity securities for fourth quarter of 2005 are as follows:

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid Per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (1)
October 1 – October 31	367,475 (2)	$42.45	N/A	N/A
November 1 – November 30	—	—	N/A	N/A
December 1 – December 31	—	—	N/A	N/A
Total	367,475	$42.45	N/A	N/A

(1) At December 31, 2005, Progress Energy did not have any publicly announced plans or programs to purchase shares of its common stock.
(2) All shares were purchased in open-market transactions by the plan administrator to satisfy share delivery requirements under the Progress Energy 401(k) Savings and Stock Ownership Plan (See Note 10B).

PEC

Since 2000, the Parent has owned all of PEC's common stock, and as a result there is no established public trading market for the stock. PEC has not issued or repurchased any equity securities since becoming a wholly owned subsidiary of the Parent. For the past three years, PEC has paid quarterly dividends to the Parent totaling the amounts shown in PEC's Statements of Common Equity included in the financial statements in PART II, ITEM 8. PEC has provisions restricting dividends in certain circumstances (See Notes 10A and 12B). PEC does not have any equity compensation plans under which its equity securities are issued.

PEF

All shares of PEF's common stock are owned by Florida Progress, and as a result there is no established public trading market for the stock. PEF did not issue or repurchase any equity securities during 2005. During 2005, PEF paid no dividends to Florida Progress. During 2004 and 2003, PEF paid quarterly dividends to Florida Progress totaling the amounts shown in PEF's Statements of Common Equity included in the financial statements in PART II, ITEM 8. PEF has provisions restricting dividends in certain circumstances (See Note 12). PEF does not have any equity compensation plans under which its equity securities are issued.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

The selected consolidated financial data should be read in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this report.

Progress Energy

	Years ended December 31				
(in millions, except per share data)	**2005**	2004 (a)	2003 (a)	2002 (a)	2001 (a)
Operating results					
Operating revenues	**$ 10,108**	$ 8,525	$ 7,799	$ 7,258	$ 7,209
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	**$ 727**	$ 729	$ 811	$ 584	$ 728
Net income	**$ 697**	$ 759	$ 782	$ 528	$ 542
Per share data					
Basic earnings					
Income from continuing operations	**$ 2.95**	$ 3.01	$ 3.42	$ 2.69	$ 3.56
Net income	**$ 2.82**	$ 3.13	$ 3.30	$ 2.43	$ 2.65
Diluted earnings					
Income from continuing operations	**$ 2.94**	$ 3.00	$ 3.40	$ 2.68	$ 3.55
Net income	**$ 2.82**	$ 3.12	$ 3.28	$ 2.42	$ 2.64
Assets	**$ 27,023**	$ 26,044	$ 26,147	$ 24,378	$ 23,815
Capitalization					
Common stock equity	**$ 8,038**	$ 7,633	$ 7,444	$ 6,677	$ 6,004
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**43**	36	30	18	12
Long-term debt, net (b)	**10,446**	9,521	9,934	9,747	8,619
Current portion of long-term debt	**513**	349	868	275	688
Short-term obligations	**175**	684	4	695	942
Total capitalization and total debt	**$ 19,308**	$ 18,316	$ 18,373	$ 17,505	$ 16,358
Dividends declared per common share	**$ 2.38**	$ 2.32	$ 2.26	$ 2.20	$ 2.14

(a) Operating results and balance sheet data have been restated for discontinued operations.
(b) Includes long-term debt to affiliated trust of $270 million at December 31, 2005, 2004 and 2003 (See Note 24).

PEC

(in millions)	Years Ended December 31 2005	2004	2003	2002	2001
Operating results					
Operating revenues	**$ 3,991**	$ 3,629	$ 3,600	$ 3,554	$ 3,360
Net income	**$ 493**	$ 461	$ 482	$ 431	$ 364
Earnings for common stock	**$ 490**	$ 458	$ 479	$ 428	$ 361
Assets	**$ 11,502**	$ 10,787	$ 10,938	$ 10,442	$ 10,640
Capitalization					
Common stock equity	**$ 3,118**	$ 3,072	$ 3,237	$ 3,089	$ 3,095
Preferred stock – not subject to mandatory redemption	**59**	59	59	59	59
Long-term debt, net	**3,667**	2,750	3,086	3,048	2,698
Current portion of long-term debt	**–**	300	300	–	600
Short-term obligations (a)	**84**	337	29	438	309
Total capitalization and total debt	**$ 6,928**	$ 6,518	$ 6,711	$ 6,634	$ 6,761

(a) Includes notes payable to affiliated companies, related to the money pool program, of $11 million, $116 million, $25 million and $48 million at December 31, 2005, 2004, 2003 and 2001, respectively.

PEF

The information called for by ITEM 6 is omitted for PEF 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 combined Management's Discussion and Analysis is separately filed by Progress Energy, Inc. (Progress Energy), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF). Information contained herein relating to PEC and PEF individually is filed by such company on its own behalf. As used in this report, Progress Energy [which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis] is at times referred to as "we," "our" or "us." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF.

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 ITEM 1A, "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.

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

PROGRESS ENERGY

INTRODUCTION

Our reportable business segments and their primary operations include:

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

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

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

STRATEGY

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

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

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

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

While our synthetic fuel operations currently provide significant net earnings that are scheduled to expire at the end of 2007 and are subject to various risks as described under the “Synthetic Fuel Tax Credits” section of OTHER MATTERS below, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred tax credits are ultimately utilized. The Code’s Section 29 (Section 29) credits that have been generated through December 31, 2005, but not yet utilized are currently carried forward indefinitely as alternative minimum tax credits and will provide positive cash flow when utilized. At December 31, 2005, the amount of these deferred tax credits was $922 million. See Note 23D and ITEM 1A “Risk Factors” for additional information on our synthetic fuel operations.

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

The Parent’s ratings outlook was changed to “stable” from “negative” in November 2005 by Standard & Poor’s (S&P). S&P cited the resolution of several regulatory issues in Florida and the expectation of increased likelihood that our financial performance will improve over the next two years in its ratings action. Moody’s Investors Service, Inc. (Moody’s) has had a “negative” outlook for the Parent since October 2004 and Fitch Rating’s outlook for the Parent has been “stable” since February 2003. See “Credit Rating Matters” and “Guarantees” Section under FUTURE LIQUIDITY AND CAPITAL RESOURCES below and ITEM 1A, “Risk Factors” for more information regarding the potential impact on our financial condition and results of operations resulting from a ratings downgrade.

REGULATED UTILITIES

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

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

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

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

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

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

The Utilities successfully resolved major state regulatory issues in 2005, including an agreement on base rates in Florida, storm cost recovery in Florida and fuel recovery filings in South Carolina, North Carolina and Florida. The

Utilities continue to monitor progress toward a more competitive environment. No retail electric restructuring legislation has been introduced in the jurisdictions in which PEC and PEF operate. As part of the Clean Smokestacks Act in North Carolina (Clean Smokestacks Act), PEC is operating under a base rate freeze in North Carolina through 2007. The PEF base rate settlement extends through 2009. See Note 7 for further discussion of the Utilities' retail rates.

NONREGULATED BUSINESSES

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

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

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

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

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

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

The Progress Registrants are subject to various risks. For a complete discussion of these risks, see the ITEM 1A, "Risk Factors."

RESULTS OF OPERATIONS

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

OVERVIEW

FOR 2005 AS COMPARED TO 2004 AND 2004 AS COMPARED TO 2003

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

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

Partially offsetting these items were:

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

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

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

Partially offsetting these items were:

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

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

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

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

Cost-Management Initiative

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

PROGRESS ENERGY CAROLINAS

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

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

REVENUES

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

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

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

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

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

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

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

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $1.390 billion for 2005, which represents a $253 million increase compared to the same period in the prior year. Fuel used in electric generation increased $200 million to $1.036 billion compared to the prior year. This increase is due to a $308 million increase in fuel used in generation due to higher fuel costs, a change in generation mix and increased volume. Higher fuel costs are being driven primarily by an increase in coal and natural gas prices. Outages at several facilities during the year resulted in increased combustion turbine generation, which has a higher average fuel cost. See ITEM 1, “Fuel and Purchased Power” of ELECTRIC-PEC for a summary of average fuel costs. The increase in fuel used in generation is offset by a reduction in deferred fuel expense as a result of the under-recovery of current period fuel costs. Purchased power expenses increased $53 million to $354 million compared to prior year. The increase in purchased power is due primarily to a change in volume partially offset by a decrease in price.

Fuel and purchased power expenses were $1.137 billion for 2004, which represents a $16 million increase compared to the same period in 2003. Fuel used in electric generation increased $11 million to $836 million compared to the same period in 2003. This increase was due to a $78 million increase in fuel used in generation due to higher fuel costs and a change in generation mix. Higher fuel costs were driven primarily by an increase in coal prices. Outages at several facilities during the year resulted in increased combustion turbine generation, which has a higher average fuel cost. See Part I, ITEM 1, “Fuel and Purchased Power” of ELECTRIC-PEC for a summary of average fuel costs. The increase in fuel used in generation is offset by a reduction in deferred fuel expense as a result of the under-recovery of fuel costs during 2004. Purchased power expenses increased $5 million to $301 million compared to prior year. The increase in purchased power is due primarily to an increase in price.

Operation and Maintenance

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

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

Depreciation and Amortization

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

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

Taxes Other than on Income

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

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

Impairment of Investments

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

Other, Net

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

Income Tax Expense

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

Cumulative Effect of Changes in Accounting Principles

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

PROGRESS ENERGY FLORIDA

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

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

REVENUES

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

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

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

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

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

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

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $2.017 billion in 2005, which represents a $275 million increase compared to 2004. This increase is due to increases in fuel used in electric generation and purchased power expenses of $148 million and $127 million, respectively. Higher system requirements and increased fuel costs in the current year account for $342 million of the increase in fuel used in electric generation. See ITEM 1, "Fuel and Purchased Power" of ELECTRIC-PEF for a summary of average fuel costs. The increase in fuel used in generation is offset by a reduction in deferred fuel expense as a result of the under-recovery of current period fuel costs. Purchased power increased primarily due to higher prices of purchases in the current year as a result of increased fuel costs.

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

Operation and Maintenance

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

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

Depreciation and Amortization

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

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

Taxes Other than on Income

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

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

Interest Expense

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

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

Income Tax Expense

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

PROGRESS VENTURES

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

The following summarizes segment profits of Progress Ventures:

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

COMPETITIVE COMMERCIAL OPERATIONS

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

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

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

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

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

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

NATURAL GAS OPERATIONS

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

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

Natural gas profits increased $51 million in 2004 compared to 2003. This increase is attributable primarily to the gain recognized on the sale of the North Texas gas operations assets during the year. In addition, an increase in production, coupled with higher gas prices in 2004, contributed to the increased earnings in 2004 as compared to

2003. Production levels increased resulting from the acquisition of North Texas Gas in late February 2003 and increased drilling in 2004. Volumes and prices increased 21 percent and 16 percent, respectively, for 2004 compared to 2003.

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

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

COAL AND SYNTHETIC FUELS

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

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

SYNTHETIC FUEL OPERATIONS

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

Results from the synthetic fuel operations are summarized below:

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

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

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

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

COAL TERMINALS AND MARKETING

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

CORPORATE OVERHEAD AND OTHER OPERATIONS

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

CORPORATE AND OTHER

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

OTHER NONREGULATED BUSINESS AREAS

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

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

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

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

CORPORATE SERVICES

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

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

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

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

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

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

DISCONTINUED OPERATIONS

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

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

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

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

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

UTILITY REGULATION

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

ASSET IMPAIRMENTS

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

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

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

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

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

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

GOODWILL

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

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

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

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

SYNTHETIC FUELS TAX CREDITS

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

In addition, Section 29 provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold value (the Threshold Price), the amount of the Section 29 tax credits are reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. We do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits related to synthetic fuel production in 2005. For 2006 synthetic fuel production, the 2006 Annual Average Price is not known until after the end of the year; we will record the 2006 tax credits based on our estimates of what we believe the Annual Average Price will be for 2006. These estimates are based on oil prices in the futures market. Any portion of the tax credits that would be phased out based on the projected 2006 Annual Average Price exceeding the Threshold Price are not recorded. We estimate that the 2006 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $66 per barrel, based on estimated inflation adjustments for 2005 and 2006. The monthly Domestic Crude Oil First Purchases Price published by the Energy Information Agency (EIA) has recently averaged approximately $5 lower than the corresponding monthly New York Mercantile Exchange (NYMEX) settlement price for light sweet crude oil. As of January 31, 2006, the average NYMEX futures price for light sweet crude oil for calendar year 2006 was $69 per barrel. Based upon the estimated 2006 Threshold Price and Phase-out Price, if oil prices for 2006 remained at the January 31, 2006 average futures price level of $69 per barrel for the entire year in 2006, we currently estimate that the synthetic fuel tax credit amount for 2006 would be reduced by approximately 75 percent to 85 percent. See further discussion in "OTHER MATTERS" below, Note 23D and ITEM 1A, "Risk Factors."

PENSION COSTS

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

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

$38 million recognized in 2005, excluding the effect of special termination benefits that were recorded in 2005 due to our early retirement program. A $123 million charge was recorded in 2005 for those special termination benefits.

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

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

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

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

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

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

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

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

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

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. Risk factors associated with credit facilities and credit ratings are discussed below and in ITEM 1A, "Risk Factors."

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

HISTORICAL FOR 2005 AS COMPARED TO 2004 AND 2004 AS COMPARED TO 2003

CASH FLOWS FROM OPERATIONS

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

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

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

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

INVESTING ACTIVITIES

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

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

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

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

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

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

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

During 2003, we acquired approximately 200 natural gas-producing wells for a cash purchase price of $168 million. We also acquired a long-term full-requirements power supply agreement with Jackson Electric Membership Corporation (Jackson) for a cash payment of $188 million (See Notes 3C and 3D).

FINANCING ACTIVITIES

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

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

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

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

2006

- On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010. These senior notes are unsecured. Interest on the Floating

Rate Senior Notes will be based on three-month London Inter Bank Offering Rate (LIBOR) plus 45 basis points and will be reset quarterly. We used the net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006. Pending the application of proceeds as described above, we invested the net proceeds in short-term, interest-bearing, investment-grade securities.

2005

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

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

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

- In January 2005, Progress Energy used proceeds from the issuance of commercial paper to pay off $260 million of RCA loans at the Utilities, which included $90 million at PEC and $170 million at PEF. PEF subsequently used money pool borrowings to reduce its outstanding commercial paper balance.

- On January 31, 2005, Progress Energy entered into a new $600 million RCA, which was scheduled to expire on December 30, 2005. This facility was added to provide additional liquidity, to the extent necessary, during 2005 due in part to the uncertainty of the timing of storm restoration cost recovery from the hurricanes in Florida during 2004. On February 4, 2005, $300 million was drawn under the Progress Energy $600 million RCA to reduce commercial paper and pay off the remaining amount of loans outstanding under other RCA facilities, which consisted of $160 million at Progress Energy and, through the money pool, $55 million at PEF. As discussed below, the maximum size of the Progress Energy RCA was reduced to $300 million on March 22, 2005, and subsequently terminated on May 16, 2005.

- On March 22, 2005, PEC issued $300 million of First Mortgage Bonds, 5.15% Series due 2015, and $200 million of First Mortgage Bonds, 5.70% Series due 2035. The net proceeds from the sale of the bonds were used to pay at maturity $300 million of PEC's 7.50% Senior Notes on April 1, 2005, and reduce the outstanding balance of PEC's commercial paper. Pursuant to the terms of Progress Energy's $600 million RCA, commitments were reduced to $300 million, effective March 22, 2005.

- In March 2005, Progress Energy's $1.1 billion five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65 percent to 68 percent due to the potential impacts of a proposed interpretation of SFAS No. 109 regarding accounting rules for uncertain tax positions (See Note 2).

- On March 28, 2005, PEC entered into a new $450 million five-year RCA with a syndication of financial institutions. The PEC RCA will be used to provide liquidity support for PEC's issuances of commercial paper and other short-term obligations. The PEC RCA is scheduled to expire on June 28, 2010. The new $450 million PEC RCA replaced PEC's $285 million three-year RCA and $165 million 364-day RCA, which were each terminated effective March 28, 2005. Fees and interest rates under the new PEC RCA are to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P. The PEC RCA includes a defined maximum total debt to capital ratio of 65 percent. The PEC RCA also contains various cross-default and other acceleration provisions, including a cross-default provision for defaults of indebtedness in excess of $35 million. The PEC RCA does not include a no material adverse change representation for borrowings or a financial covenant for interest coverage.

- On March 28, 2005, PEF entered into a new $450 million five-year RCA with a syndication of financial institutions. The PEF RCA will be used to provide liquidity support for PEF's issuances of commercial paper and other short-term obligations. The PEF RCA is scheduled to expire on March 28, 2010. The new $450 million PEF RCA replaced PEF's $200 million three-year RCA and $200 million 364-day RCA, which were each terminated effective March 28, 2005. Fees and interest rates under the new PEF RCA are to be determined based upon the credit rating of PEF's long-term unsecured senior noncredit enhanced debt, currently rated as A3 by Moody's and BBB- by S&P. The PEF RCA includes a defined maximum total debt to capital ratio of 65%. The PEF RCA also contains various cross-default and other acceleration provisions, including a cross-default provision for defaults of indebtedness in excess of $35 million. The PEF RCA does not include a no material adverse change representation for borrowings or a financial covenant for interest coverage.

- In May 2005, Progress Energy used proceeds from the issuance of commercial paper to pay off $300 million of its $600 million RCA.

- On May 16, 2005, PEF issued $300 million of First Mortgage Bonds, 4.50% Series due 2010. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of commercial paper. Pursuant to the terms of the Progress Energy $600 million RCA, commitments were completely reduced and the Progress Energy $600 million RCA was terminated, effective May 16, 2005.

- On July 1, 2005, PEF paid at maturity $45 million of its 6.72% Medium-Term Notes, Series B with commercial paper proceeds.

- On July 28, 2005, PEC filed a shelf registration statement with the SEC to provide $1.0 billion of capacity. The registration statement was declared effective on December 23, 2005, and will allow PEC to issue various securities, including First Mortgage Bonds, Senior Notes, Debt Securities and Preferred Stock.

- On July 28, 2005, PEF filed a shelf registration statement with the SEC to provide $1.0 billion of capacity. The registration statement was declared effective on December 23, 2005, and will allow PEF to issue various securities, including First Mortgage Bonds, Debt Securities and Preferred Stock.

- In addition to the ongoing RCAs, Progress Energy entered into a new $800 million 364-day credit agreement on November 21, 2005, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, we retired $800 million of our 6.75% Senior Notes, thus effectively terminating the 364-day credit agreement.

- On November 30, 2005, PEC issued $400 million of First Mortgage Bonds, 5.25% Series due 2015. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of short-term debt, including commercial paper borrowings and borrowings under our internal money pool, and for general corporate purposes.

- On December 13, 2005, PEF issued $450 million of Series A Floating Rate Senior Notes due 2008. These senior notes are unsecured. Interest on the Floating Rate Senior Notes will be based on three-month LIBOR plus 40 basis points and will be reset quarterly. The net proceeds from the sale of the bonds were used to reduce the outstanding balance of short-term debt, including commercial paper borrowings and borrowings under our internal money pool, and for general corporate purposes.

- Progress Energy issued approximately 4.8 million shares of our common stock for approximately $208 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans, net of purchases of restricted shares. For 2005, the dividends paid on common stock were approximately $582 million.

2004

- Progress Energy paid at maturity $500 million in senior unsecured notes and entered into a new $1.1 billion five-year line of credit, expiring August 5, 2009. This facility replaced Progress Energy's $250 million 364-day line of credit and its three-year $450 million line of credit, which were both scheduled to expire in November 2004. Proceeds from the sale of natural gas assets were used to extinguish Genco's $241 million bank facility, and Progress Capital Holdings, Inc., paid at maturity $25 million of Medium-Term Notes.

- PEC redeemed $39 million of Pollution Control Obligations and paid at maturity $300 million in First Mortgage Bonds. PEC extended to July 27, 2005, its $165 million 364-day line of credit, which was scheduled to expire on July 29, 2004.

- PEF paid at maturity $40 million in Medium-Term Notes.

- Progress Energy issued approximately 1.7 million shares of our common stock for approximately $73 million in net proceeds from our Investor Plus Stock Purchase Plan and our employee benefit and stock option plans, net of purchases of restricted shares. For 2004, the dividends paid on common stock were approximately $558 million.

2003

- Progress Energy obtained a three-year financing order, allowing it to issue up to $2.8 billion of long-term securities, $1.5 billion of short-term debt, and $3 billion in parent guarantees. Progress Capital Holdings, Inc., paid at maturity $58 million in Medium-Term Notes. Genco terminated its $50 million working capital credit facility. Under its related construction facility, Genco had drawn $241 million at December 31, 2003.

- PEC redeemed $250 million and issued $600 million in First Mortgage Bonds.

- PEF redeemed $250 million, issued $950 million and paid at maturity $180 million in First Mortgage Bonds. PEF also paid at maturity $35 million in Medium-Term Notes.

- Progress Energy issued approximately 7.6 million shares of common stock for approximately $304 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit plans, net of purchases of restricted shares. For 2003, the dividends paid on common stock were approximately $541 million.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

Please review ITEM 1A, "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.

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

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

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

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

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

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

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

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

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

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

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

CAPITAL EXPENDITURES

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

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

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

Regulated capital expenditures for 2006, 2007 and 2008 in the table above include approximately $370 million, $420 million and $560 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2006, 2007 and 2008 include $320 million, $240 million and $190 million, respectively, at PEC and $50 million, $180 million and $370 million, respectively, at PEF. We currently estimate total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, a portion of which are eligible for regulatory recovery, to be in excess of $1.0 billion each at PEC and PEF, respectively, through 2018, which is the latest compliance target date for current air and water quality regulations. See Note 22 for further discussion of our environmental compliance costs and related recovery of costs.

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

OTHER CASH NEEDS

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

CREDIT FACILITIES

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

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

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

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

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

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

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

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

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

CREDIT RATING MATTERS

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

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

(a) Guaranteed by Progress Energy, Inc. and Florida Progress.

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

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

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

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

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

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

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

GUARANTEES

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

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

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

MARKET RISK AND DERIVATIVES

Under our risk management policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 18 and ITEM 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

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

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

(a) Our maturing debt obligations are generally expected to be refinanced with new debt issuances in the capital markets.
(b) Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective at December 31, 2005, and the LIBOR forward curve at December 31, 2005, respectively.
(c) Fuel and purchased power commitments represent the majority of our remaining future commitments after debt obligations. Essentially all of our fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.
(d) Projected pension funding status is based on current actuarial estimates and is subject to future revision.
(e) In 2008, PEC must begin transitioning amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.
(f) We have certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties) through 2007 (See Note 23D).

OTHER MATTERS

SYNTHETIC FUELS TAX CREDITS

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

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

Our synthetic fuel operations and related risks are described in more detail in Note 23D and ITEM 1A, “Risk Factors.”

REGULATORY ENVIRONMENT

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

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

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

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

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

LEGAL

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

NUCLEAR

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

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

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

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

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

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

ENVIRONMENTAL MATTERS

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

NEW ACCOUNTING STANDARDS

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

PEC

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's Management's Discussion and Analysis of Financial Condition and Results of Operations, insofar as they relate to PEC: RESULTS OF OPERATIONS; APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES; LIQUIDITY AND CAPITAL RESOURCES; FUTURE OUTLOOK and OTHER MATTERS.

The following Management's Discussion and Analysis and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review ITEM 1A, "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.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

PEC has primarily used a combination of debt securities, first mortgage bonds, pollution control bonds, commercial paper facilities and revolving credit agreements for liquidity needs in excess of cash provided by operations. PEC also participates in the utility money pool, which allows PEC and PEF to lend and borrow between each other.

On March 22, 2005, PEC issued $300 million of First Mortgage Bonds, 5.15% Series due 2015, and $200 million of First Mortgage Bonds, 5.70% Series due 2035. On March 28, 2005, PEC entered into a new $450 million five-year RCA that replaced PEC's $285 million three-year RCA and $165 million 364-day RCA, which were each terminated effective March 28, 2005. On November 30, 2005, PEC issued $400 million of First Mortgage Bonds, 5.25% Series due 2015. See further discussion of these items above in Progress Energy under "Financing Activities."

On July 28, 2005, PEC filed a shelf registration statement with the SEC to provide $1.0 billion of capacity. The registration statement was declared effective on December 23, 2005.

As discussed above in the Progress Energy "Credit Rating Matters," in November 2005, S&P revised PEC's outlook and short-term rating from negative to stable and A-3 to A-2, respectively. The business position for PEC remains a '5' (satisfactory). On December 6, 2005, S&P lowered the BBB rating on PEC's senior unsecured notes to BBB-.

PEC expects to have sufficient resources to meet its future obligations either through internally generated funds, its short term-term borrowing facilities or through the issuance of long-term debt or preferred stock.

CASH FLOW DISCUSSION

HISTORICAL FOR 2005 AS COMPARED TO 2004 AND 2004 AS COMPARED TO 2003

In 2005, cash provided by operating activities decreased when compared to 2004. The $44 million decrease in operating cash flow was primarily due to an $88 million increase in the under-recovery of fuel cost driven by rising fuel costs, partially offset by a $55 million improvement in working capital, including the impact of a prepayment received from a wholesale customer. In November 2005, PEC entered into a contract with the PWC in which the PWC prepaid $141 million in exchange for future capacity and energy power sales. The prepayment is expected to cover approximately two years of electricity service and includes a prepayment discount of approximately $16 million. The improvement in working capital needs for 2005 compared to 2004 was mainly driven by the current portion of the prepayment received from the PWC as discussed above and favorability from tax payments, partially offset by increases in the change in receivables and inventory purchases, primarily coal. The increase in the change in receivables is primarily due to increased sales driven by weather, timing of receipts and the impact of excess generation sales. In 2005, PEC filed requests with the North Carolina and South Carolina state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. See "Future Liquidity and Capital Resources" under Progress Energy above and Note 7.

In 2004, cash provided by operating activities decreased when compared to 2003. The $157 million decrease was caused primarily by an $89 million increase from under-recovery of fuel costs and a $77 million decrease in payables to affiliates.

In 2005, cash used in investing activities increased when compared to 2004. The $326 million increase is due primarily to a $253 million decrease in net proceeds from available-for-sale securities and other long-term investments and $62 million in additional capital expenditures for property, primarily related to an increase in spending for compliance with the Clean Smokestacks Act, and nuclear fuel additions. Available-for-sale securities and other long-term investments include marketable debt securities and investments held in nuclear decommissioning and benefit investment trusts.

In 2004, cash used in investing activities decreased approximately $207 million when compared with 2003. The decrease is primarily due to net proceeds from available for sale securities and other long-term investments in 2004, compared to net purchases in 2003. The decrease is partially offset by an increase in capital expenditures, primarily related to an increase in spending for compliance with the Clean Smokestacks Act, and an increase in nuclear fuel additions.

See the discussion above for Progress Energy under "Financing Activities" for information regarding PEC's financing activities.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

PEC's estimated capital requirements for 2006, 2007 and 2008 are approximately $855 million, $800 million and $860 million, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and for environmental control facilities as discussed above in "Capital Expenditures" under Progress Energy.

PEC expects to fund its capital requirements primarily through internally generated funds. In addition, PEC has $450 million in credit facilities that support the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEC's working capital requirements. To the extent necessary, PEC may access the capital markets to meet its liquidity requirements.

The following table shows PEC's total debt to total capitalization ratios at December 31:

	2005	2004
Common stock equity	**45.0%**	47.1%
Preferred stock	**0.9%**	0.9%
Total debt	**54.1%**	52.0%

See the discussion above under Progress Energy and Note 12 for further discussion of PEC's future liquidity and capital resources.

<u>OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS</u>

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

MARKET RISK AND DERIVATIVES

Under its risk management policy, PEC 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 ITEM 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

CONTRACTUAL OBLIGATIONS

PEC 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 actual amounts. Further disclosure regarding PEC's contractual obligations is included in the respective notes to the PEC Consolidated Financial Statements. PEC takes into consideration the future commitments when assessing its liquidity and future financing needs. The following table reflects PEC's contractual cash obligations and other commercial commitments at December 31, 2005, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a) (See Note 12)	$ 3,691	$ –	$ 500	$ 406	$ 2,785
Interest payments on long-term debt and interest rate derivatives (b)	2,044	202	370	293	1,179
Capital lease obligations (See Note 23B)	26	2	5	5	14
Operating leases (See Note 23B)	304	36	62	48	158
Fuel and purchased power (c) (See Note 23A)	4,189	1,005	1,499	584	1,101
Other purchase obligations (See Note 23A)	55	14	41	–	–
Minimum pension funding requirements (d)	147	1	142	4	–
Other commitments (e)	131	–	13	26	92
Total	$ 10,587	$ 1,260	$ 2,632	$ 1,366	$ 5,329

(a) PEC's maturing debt obligations are generally expected to be refinanced with new debt issuances in the capital markets.
(b) Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective at December 31, 2005, and the LIBOR forward curve at December 31, 2005, respectively.
(c) Fuel and purchased power commitments represent the majority of PEC's remaining future commitments after its debt obligations. Essentially all of PEC's fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina and South Carolina regulations and therefore do not require separate liquidity support.
(d) Projected pension funding status is based on current actuarial estimates and is subject to future revision.
(e) In 2008, PEC must begin transitioning amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10% must be transitioned each year.

PEF

The information required by this item is incorporated herein by reference to the following portions of Progress Energy's Management's Discussion and Analysis of Financial Condition and Results of Operations, insofar as they relate to PEF: RESULTS OF OPERATIONS; APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES; LIQUIDITY AND CAPITAL RESOURCES; FUTURE OUTLOOK and OTHER MATTERS.

The following Management's Discussion and Analysis and the information incorporated herein by reference contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review ITEM 1A, "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.

LIQUIDITY AND CAPITAL RESOURCES

OVERVIEW

PEF has primarily used a combination of debt securities, first mortgage bonds, pollution control bonds, commercial paper facilities and revolving credit agreements for liquidity needs in excess of cash provided by operations. PEF also participates in the utility money pool, which allows PEC and PEF to lend and borrow between each other.

On March 28, 2005, PEF entered into a new $450 million five-year RCA that replaced PEF's $200 million three-year RCA and $200 million 364-day RCA, which were each terminated effective March 28, 2005. On May 16, 2005, PEF issued $300 million of First Mortgage Bonds, 4.5% Series due 2010. On July 1, 2005, PEF paid at maturity $45 million of its 6.72% Medium-Term Notes, Series B. On December 13, 2005, PEF issued $450 million of Series A Floating Rate Senior Notes due 2008. See further discussion above in Progress Energy under "Financing Activities."

On July 28, 2005, PEF filed a shelf registration statement with the SEC to provide $1.0 billion of capacity. The registration statement was declared effective on December 23, 2005.

As discussed above in the Progress Energy "Credit Rating Matters," in November 2005, S&P revised PEF's outlook and short-term rating from negative to stable and A-3 to A-2, respectively. The business position for PEF was improved to a '4' (strong). On December 6, 2005, S&P lowered the BBB rating on PEF's senior unsecured notes to BBB-.

PEF expects to have sufficient resources to meet its future obligations either through internally generated funds, its short term-term borrowing facilities or through the issuance of long-term debt or preferred stock.

CASH FLOW DISCUSSION

HISTORICAL FOR 2005 AS COMPARED TO 2004 AND 2004 AS COMPARED TO 2003

Cash from operating activities for 2005 decreased when compared with 2004. The $103 million decrease in operating cash flow was primarily due to a $210 million increase in the under-recovery of fuel costs driven by rising fuel costs and a $32 million increase in working capital needs, partially offset by a $193 million reduction in storm cost spending at PEF in 2005 compared to 2004. The increase in working capital needs for 2005 compared to 2004 was mainly driven by a $50 million increase in the change in receivables, primarily due to increased sales largely driven by rising fuel prices and timing of receipts. In 2005, PEF filed requests with the Florida state commission seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. PEF also received approval from the FPSC authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" below and Note 7 for additional information.

PEF's operating cash flow increased by $85 million to $533 million in 2004, due primarily to 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 of $204 million, offset by storm costs.

In 2005, cash used in investing activities increased when compared to 2004. The $10 million increase is due primarily to $47 million in nuclear fuel additions, partially offset by $42 million in proceeds from the sale of Winter Park distribution assets in June 2005 (See Note 7C).

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. Cash used in investing activities was higher in 2003 primarily due to nuclear fuel additions.

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 additional generating units at the Hines site. Hines Unit 2 was placed into service in December 2003 and Hines Unit 3 was placed into service in November 2005. In addition, PEF received approval to begin construction of a fourth unit at the Hines Energy Complex and ground was broken for the fourth unit on February 2, 2006.

See the discussion above for Progress Energy under "Financing Activities" for information regarding PEF's financing activities.

FUTURE LIQUIDITY AND CAPITAL RESOURCES

At PEF, cash from operations is the primary source of cash for the utility's capital expenditures. PEF's estimated capital requirements for 2006, 2007 and 2008 are approximately $725 million, $740 million and $850 million, respectively, and primarily reflect construction expenditures to support customer growth, add regulated generation, upgrade existing facilities and for environmental control facilities as discussed above in "Capital Expenditures" under Progress Energy.

PEF expects to fund its capital requirements primarily through internally generated funds. In addition, PEF has $450 million in credit facilities that support the issuance of commercial paper. Access to the commercial paper market and the utility money pool provide additional liquidity to help meet PEF's working capital requirements. To the extent necessary, PEF may access the capital markets to meet its liquidity requirements.

The following table shows PEF's total debt to total capitalization ratios at December 31:

	2005	2004
Common stock equity	**48.6%**	48.5%
Preferred stock	**0.6%**	0.7%
Total debt	**50.8%**	50.8%

See the discussion above under Progress Energy and Note 12 for further discussion of PEF's future liquidity and capital resources.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

See Note 23A for information on PEF's contractual obligations at December 31, 2005.

MARKET RISK AND DERIVATIVES

Under its risk management policy, 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 18 and ITEM 7A, "Quantitative and Qualitative Disclosures About Market Risk," for a discussion of market risk and derivatives.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

The following disclosures about market risk contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review ITEM 1A, “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.

PROGRESS ENERGY, INC.

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

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

INTEREST RATE RISK

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

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

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

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

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

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

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

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

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

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

MARKETABLE SECURITIES PRICE RISK

The Utilities maintain trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning their nuclear plants. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. At December 31, 2005 and 2004, the fair value of these funds was $1.13 billion and $1.04 billion, respectively, including $640 million and $581 million, respectively, for PEC and $493 million and $463 million, respectively, for PEF. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

CONTINGENT VALUE OBLIGATIONS MARKET VALUE RISK

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

COMMODITY PRICE RISK

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

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

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

ECONOMIC DERIVATIVES

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

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

CASH FLOW HEDGES

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

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Fair value of assets	**$ 170**	$ –	**$ 7**	$ –	**$ –**	$ –
Fair value of liabilities	**(58)**	(15)	**(4)**	–	**–**	–
Fair value, net	**$ 112**	$ (15)	**$ 3**	$ –	**$ –**	$ –

PEC

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

The information required by this item is incorporated herein by reference to the Quantitative and Qualitative Disclosures About Market Risk insofar as it relates to PEC.

INTEREST RATE RISK

The following tables provide information at about PEC's interest rate risk sensitive instruments:

December 31, 2005 (dollars in millions)	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**	**Fair Value December 31, 2005**
Fixed-rate long-term debt	**$ –**	**$ 200**	**$ 300**	**$ 400**	**$ 6**	**$ 2,165**	**$ 3,071**	**$ 3,169**
Average interest rate	**–**	**6.80%**	**6.65%**	**5.95%**	**6.30%**	**5.79%**	**5.96%**	
Variable-rate long-term debt	**–**	**–**	**–**	**–**	**–**	**$ 620**	**$ 620**	**$ 620**
Average interest rate	**–**	**–**	**–**	**–**	**–**	**3.04%**	**3.04%**	

December 31, 2004 (dollars in millions)	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value December 31, 2004
Fixed-rate long-term debt	$ 300	–	$ 200	$ 300	$ 400	$ 1,249	$ 2,449	$ 2,686
Average interest rate	7.50%	–	6.80%	6.65%	5.95%	6.13%	6.38%	
Variable-rate long-term debt	–	–	–	–	–	$ 620	$ 620	$ 621
Average interest rate	–	–	–	–	–	1.71%	1.71%	
Interest rate forward contracts	–	–	–	–	–	$ 131	$ 131	$ (2)
Average pay rate	–	–	–	–	–	4.90%	4.90%	
Average receive rate	–	–	–	–	–	(a)	(a)	

(a) Rate is 3-month LIBOR, which was 2.56% at December 31, 2004.

COMMODITY PRICE RISK

PEC 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. PEC's exposure to these fluctuations is significantly limited by cost-based regulation. 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. PEC may engage in limited economic hedging activity using natural gas and electricity financial instruments. See "Commodity Price Risk" discussion under Progress Energy above and Note 18 for additional information with regard to PEC's commodity contracts and use of derivative financial instruments.

PEF

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

The information required by this item is incorporated herein by reference to the Quantitative and Qualitative Disclosures About Market Risk insofar as it relates to PEF.

INTEREST RATE RISK

The following tables provide information at about PEF's interest rate risk sensitive instruments:

December 31, 2005 (dollars in millions)	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**	**Fair Value December 31, 2005**
Fixed-rate long-term debt	**$ 48**	**$ 89**	**$ 82**	**–**	**$ 300**	**$ 1,400**	**$ 1,919**	**$ 1,944**
Average interest rate	**6.76%**	**6.80%**	**6.87%**	**–**	**4.50%**	**5.65%**	**5.60%**	
Variable-rate long-term debt	**–**	**–**	**$ 450**	**–**	**–**	**$ 241**	**$ 691**	**$ 691**
Average interest rate	**–**	**–**	**4.88%**	**–**	**–**	**3.07%**	**4.25%**	

December 31, 2004 (dollars in millions)	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value December 31, 2004
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%	

COMMODITY PRICE RISK

PEF 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. PEF's exposure to these fluctuations is significantly limited by its cost-based regulation. 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 "Commodity Price Risk" discussion under Progress Energy above and Note 18 for additional information with regard to PEF's commodity contracts and use of derivative financial instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following financial statements, supplementary data and financial statement schedules are included herein:

Each of the preceding combined notes to the financial statements of the Progress Registrants are applicable to Progress Energy, Inc. but not to each of PEC and PEF. The following table sets forth which notes are applicable to each of PEC and PEF.

Registrant	**Applicable Notes**
PEC	1, 2, 5 through 10, 12 through 14, 16 through 23 and 26
PEF	1 through 10, 12 through 14, 16 through 23 and 26

Consolidated Financial Statement Schedules for the Years Ended December 31, 2005, 2004 and 2003:

All other schedules have been omitted as not applicable or are not required because the information required to be shown is included in the Financial Statements or the Combined Notes to the Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF PROGRESS ENERGY, INC.

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

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

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

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

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of INCOME

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

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

PROGRESS ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

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

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

PROGRESS ENERGY, INC.

CONSOLIDATED STATEMENTS of CASH FLOWS

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

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of CHANGES in COMMON STOCK EQUITY

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

PROGRESS ENERGY, INC.
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

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

See Notes to Progress Energy, Inc. Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.:

We have audited the accompanying consolidated balance sheets of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., and its subsidiaries (PEC) at December 31, 2005 and 2004, and the related consolidated statements of income, changes in common stock equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of PEC'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. PEC is 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 PEC'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 consolidated financial statements present fairly, in all material respects, the financial position of PEC at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

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

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of INCOME

(in millions) Years ended December 31	**2005**	2004	2003
Operating revenues			
Electric	**$ 3,990**	$ 3,628	$ 3,589
Diversified businesses	**1**	1	11
Total operating revenues	**3,991**	3,629	3,600
Operating expenses			
Fuel used in electric generation	**1,036**	836	825
Purchased power	**354**	301	296
Operation and maintenance	**941**	871	782
Depreciation and amortization	**561**	570	562
Taxes other than on income	**178**	173	162
Other	**(11)**	(12)	(8)
Diversified businesses	**1**	1	4
Total operating expenses	**3,060**	2,740	2,623
Operating income	**931**	889	977
Other income (expense)			
Interest income	**8**	4	6
Impairment of investments	**(1)**	–	(21)
Other, net	**(14)**	(1)	(19)
Total other (expense) income	**(7)**	3	(34)
Interest charges			
Interest charges	**197**	195	198
Allowance for borrowed funds used during construction	**(5)**	(3)	(1)
Total interest charges, net	**192**	192	197
Income before income taxes and cumulative effect of changes in accounting principles	**732**	700	746
Income tax expense	**239**	239	241
Income before cumulative effect of changes in accounting principles	**493**	461	505
Cumulative effect of changes in accounting principles, net of tax	**–**	–	(23)
Net income	**493**	461	482
Preferred stock dividend requirement	**3**	3	3
Earnings for common stock	**$ 490**	$ 458	$ 479

See Notes to PEC Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2005	2004
ASSETS		
Utility plant		
Utility plant in service	**$ 13,994**	$ 13,521
Accumulated depreciation	**(6,120)**	(5,806)
Utility plant in service, net	**7,874**	7,715
Held for future use	**3**	5
Construction work in progress	**399**	379
Nuclear fuel, net of amortization	**203**	186
Total utility plant, net	**8,479**	8,285
Current assets		
Cash and cash equivalents	**125**	18
Short-term investments	**191**	82
Receivables, net	**518**	397
Receivables from affiliated companies	**24**	20
Inventory	**451**	401
Deferred fuel cost	**261**	140
Income taxes receivable	**–**	59
Prepayments and other current assets	**20**	65
Total current assets	**1,590**	1,182
Deferred debits and other assets		
Regulatory assets	**421**	473
Nuclear decommissioning trust funds	**640**	581
Miscellaneous other property and investments	**188**	158
Other assets and deferred debits	**184**	108
Total deferred debits and other assets	**1,433**	1,320
Total assets	**$ 11,502**	$ 10,787
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, authorized 200 million shares, 160 million shares issued and outstanding at December 31	**$ 1,981**	$ 1,975
Unearned ESOP common stock	**(63)**	(76)
Accumulated other comprehensive loss	**(120)**	(114)
Retained earnings	**1,320**	1,287
Total common stock equity	**3,118**	3,072
Preferred stock – not subject to mandatory redemption	**59**	59
Long-term debt, net	**3,667**	2,750
Total capitalization	**6,844**	5,881
Current liabilities		
Current portion of long-term debt	**–**	300
Accounts payable	**247**	254
Payables to affiliated companies	**73**	83
Notes payable to affiliated companies	**11**	116
Interest accrued	**73**	77
Short-term obligations	**73**	221
Customer deposits	**52**	45
Taxes accrued	**100**	–
Current portion of unearned revenue	**70**	–
Other current liabilities	**185**	179
Total current liabilities	**884**	1,275
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**814**	991
Accumulated deferred investment tax credits	**133**	140
Regulatory liabilities	**1,196**	1,052
Asset retirement obligations	**949**	924
Accrued pension and other benefits	**511**	428
Other liabilities and deferred credits	**171**	96
Total deferred credits and other liabilities	**3,774**	3,631
Commitments and contingencies (Notes 22 and 23)		
Total capitalization and liabilities	**$ 11,502**	$ 10,787

See Notes to PEC Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.

CONSOLIDATED STATEMENTS of CASH FLOWS

(in millions)			
Years Ended December 31	**2005**	2004	2003
Operating activities			
Net income	**$ 493**	$ 461	$ 482
Adjustments to reconcile net income to net cash provided by operating activities			
Impairment of long-lived assets and investments	**1**	–	21
Charges for voluntary enhanced retirement program	**42**	–	–
Depreciation and amortization	**644**	658	654
Cumulative effect of changes in accounting principles, net	**–**	–	23
Deferred income taxes	**(142)**	(19)	(69)
Investment tax credit	**(8)**	(7)	(10)
Deferred fuel (credit) cost	**(144)**	(56)	33
Other adjustments to net income	**68**	50	44
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**(111)**	(4)	10
Receivables from affiliated companies	**11**	15	28
Inventories	**(91)**	(22)	(17)
Prepayments and other current assets	**9**	17	17
Accounts payable	**9**	34	(56)
Payables to affiliated companies	**(13)**	(53)	24
Other current liabilities	**239**	11	58
Regulatory assets and liabilities	**2**	9	27
Other operating activities	**23**	(18)	(36)
Net cash provided by operating activities	**1,032**	1,076	1,233
Investing activities			
Gross utility property additions	**(603)**	(519)	(445)
Proceeds from sale of assets	**14**	25	28
Nuclear fuel additions	**(79)**	(101)	(66)
Purchases of available-for-sale securities and other investments	**(1,832)**	(2,479)	(3,257)
Proceeds from sales of available-for-sale securities and other investments	**1,692**	2,592	3,000
Changes in advances to affiliates	**–**	–	50
Other investing activities	**(3)**	(3)	(2)
Net cash used in investing activities	**(811)**	(485)	(692)
Financing activities			
Proceeds from issuance of long-term debt, net	**898**	–	588
Net (decrease) increase in short-term obligations	**(148)**	217	(437)
Changes in advances from affiliates	**(105)**	91	24
Retirement of long-term debt	**(300)**	(339)	(276)
Dividends paid to parent	**(457)**	(551)	(443)
Dividends paid on preferred stock	**(3)**	(3)	(3)
Other financing activities	**1**	–	–
Net cash used in financing activities	**(114)**	(585)	(547)
Net increase (decrease) in cash and cash equivalents	**107**	6	(6)
Cash and cash equivalents at beginning of year	**18**	12	18
Cash and cash equivalents at end of year	**$ 125**	$ 18	$ 12
Supplemental disclosures of cash flow information			
Cash paid during the year – interest (net of amount capitalized)	**$ 185**	$ 185	$ 180
income taxes (net of refunds)	**$ 222**	$ 286	$ 296

See Notes to PEC Consolidated Financial Statements.

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions except shares outstanding)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2002	160	$ 1,930	$ (102)	$ (83)	$ 1,344	$ 3,089
Net income		–	–	–	482	482
Other comprehensive income		–	–	76	–	76
Comprehensive income						558
Equity contribution from parent		3	–	–	–	3
Allocation of ESOP shares		20	13	–	–	33
Preferred stock dividends at stated rates		–	–	–	(3)	(3)
Dividends paid to parent		–	–	–	(443)	(443)
Balance, December 31, 2003	160	1,953	(89)	(7)	1,380	3,237
Net income		–	–	–	461	461
Other comprehensive loss		–	–	(107)	–	(107)
Comprehensive income						354
Allocation of ESOP shares		22	13	–	–	35
Preferred stock dividends at stated rates		–	–	–	(3)	(3)
Dividends paid to parent		–	–	–	(551)	(551)
Balance, December 31, 2004	**160**	**1,975**	**(76)**	**(114)**	**1,287**	**3,072**
Net income		**–**	**–**	**–**	**493**	**493**
Other comprehensive loss		**–**	**–**	**(6)**	**–**	**(6)**
Comprehensive income						**487**
Stock-based compensation expense		**3**	**–**	**–**	**–**	**3**
Allocation of ESOP shares		**20**	**13**	**–**	**–**	**33**
Noncash dividend to parent		**(17)**	**–**	**–**	**–**	**(17)**
Preferred stock dividends at stated rates		**–**	**–**	**–**	**(3)**	**(3)**
Dividends paid to parent		**–**	**–**	**–**	**(457)**	**(457)**
Balance, December 31, 2005	**160**	**$ 1,981**	**$ (63)**	**(120)**	**$ 1,320**	**$ 3,118**

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.
CONSOLIDATED STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2005**	2004	2003
Net income	**$ 493**	$ 461	$ 482
Other comprehensive income (loss)			
Changes in net unrealized losses on cash flow hedges (net of tax (expense) benefit of ($2), $1 and ($1), respectively)	**3**	(1)	3
Reclassification adjustment for amounts included in net income (net of tax expense of $–)	**1**	–	1
Minimum pension liability adjustment (net of tax benefit (expense) of $7, $68 and ($47), respectively)	**(12)**	(106)	72
Other (net of tax expense of $1)	**2**	–	–
Other comprehensive (loss) income	**(6)**	(107)	76
Comprehensive income	**$ 487**	$ 354	$ 558

See Notes to PEC Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDER OF FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.:

We have audited the accompanying balance sheets of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) at December 31, 2005 and 2004, and the related statements of income, changes in common stock equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of PEF'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. PEF is 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 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 PEF at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements, in 2005 PEF adopted Statement of Financial Accounting Standards No. 123R and Financial Accounting Standards Board Interpretation No. 47 and in 2003 PEF adopted Statement of Financial Accounting Standards No. 143.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA

STATEMENTS of INCOME

(in millions) Years ended December 31	**2005**	2004	2003
Operating revenues	**$3,955**	$ 3,525	$ 3,152
Operating expenses			
Fuel used in electric generation	**1,323**	1,175	870
Purchased power	**694**	567	566
Operation and maintenance	**852**	630	640
Depreciation and amortization	**334**	281	307
Taxes other than on income	**279**	254	241
Other	**(26)**	(2)	–
Total operating expenses	**3,456**	2,905	2,624
Operating income	**499**	620	528
Other income			
Interest income	**1**	–	–
Other, net	**7**	3	7
Total other income	**8**	3	7
Interest charges			
Interest charges	**134**	117	97
Allowance for borrowed funds used during construction	**(8)**	(3)	(6)
Total interest charges, net	**126**	114	91
Income before income taxes	**381**	509	444
Income tax expense	**121**	174	147
Net income	**260**	335	297
Preferred stock dividend requirement	**2**	2	2
Earnings for common stock	**$ 258**	$ 333	$ 295

See Notes to PEF Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA

BALANCE SHEETS

(in millions) December 31	**2005**	2004
ASSETS		
Utility plant		
Utility plant in service	**$ 8,756**	$ 8,387
Accumulated depreciation	**(3,434)**	(2,978)
Utility plant in service, net	**5,322**	5,409
Held for future use	**9**	8
Construction work in progress	**414**	420
Nuclear fuel, net of amortization	**76**	45
Total utility plant, net	**5,821**	5,882
Current assets		
Cash and cash equivalents	**218**	12
Receivables, net	**331**	266
Receivables from affiliated companies	**11**	16
Deferred income taxes	**12**	42
Inventory	**311**	290
Deferred fuel cost	**341**	89
Derivative assets	**77**	–
Prepayments and other current assets	**23**	1
Total current assets	**1,324**	716
Deferred debits and other assets		
Regulatory assets	**351**	524
Debt issuance costs	**22**	21
Nuclear decommissioning trust funds	**493**	463
Miscellaneous other property and investments	**47**	46
Prepaid pension cost	**200**	234
Other assets and deferred debits	**60**	38
Total deferred debits and other assets	**1,173**	1,326
Total assets	**$ 8,318**	$ 7,924
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 60 million shares authorized, 100 shares issued and outstanding	**$ 1,097**	$ 1,081
Retained earnings	**1,498**	1,240
Total common stock equity	**2,595**	2,321
Preferred stock – not subject to mandatory redemption	**34**	34
Long-term debt, net	**2,554**	1,912
Total capitalization	**5,183**	4,267
Current liabilities		
Current portion of long-term debt	**48**	48
Accounts payable	**237**	262
Payables to affiliated companies	**101**	80
Notes payable to affiliated companies	**13**	178
Short-term obligations	**102**	293
Customer deposits	**148**	135
Interest accrued	**42**	46
Other current liabilities	**101**	115
Total current liabilities	**792**	1,157
Deferred credits and other liabilities		
Noncurrent income tax liabilities	**433**	489
Accumulated deferred investment tax credits	**30**	35
Regulatory liabilities	**1,189**	1,362
Asset retirement obligations	**290**	337
Accrued pension and other benefits	**257**	201
Other liabilities and deferred credits	**144**	76
Total deferred credits and other liabilities	**2,343**	2,500
Commitments and contingencies (Notes 22 and 23)		
Total capitalization and liabilities	**$ 8,318**	$ 7,924

See Notes to PEF Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA

STATEMENTS of CASH FLOWS

(in millions)

Years ended December 31	**2005**	2004	2003
Operating activities			
Net income	**$ 260**	$ 335	$ 297
Adjustments to reconcile net income to net cash provided by operating activities			
Gain on sale of operating assets	**(26)**	(1)	–
Charges for voluntary enhanced retirement program	**92**	–	–
Depreciation and amortization	**367**	310	314
Deferred income taxes and investment tax credits, net	**(50)**	110	(25)
Deferred fuel (credit) cost	**(173)**	37	(167)
Other adjustments to net income	**45**	(13)	(4)
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**(70)**	(20)	(7)
Receivables from affiliated companies	**4**	(8)	36
Inventories	**(34)**	(36)	(32)
Prepayments and other current assets	**(22)**	2	–
Accounts payable	**52**	13	12
Payables to affiliated companies	**21**	14	(7)
Other current liabilities	**(7)**	11	35
Regulatory assets and liabilities	**(76)**	(243)	(1)
Other operating activities	**47**	22	(3)
Net cash provided by operating activities	**430**	533	448
Investing activities			
Gross utility property additions	**(496)**	(492)	(526)
Nuclear fuel additions	**(47)**	–	(51)
Proceeds from sale of assets	**43**	–	1
Purchases of available-for-sale securities and other investments	**(405)**	(569)	(441)
Proceeds from sale of available-for-sale securities and other investments	**405**	569	441
Other investing activities	**(6)**	(4)	(2)
Net cash used in investing activities	**(506)**	(496)	(578)
Financing activities			
Proceeds from issuance of long-term debt, net	**744**	56	935
Net (decrease) increase in short-term obligations	**(191)**	293	(258)
Retirement of long-term debt	**(102)**	(43)	(476)
Changes in advances from affiliates	**(165)**	(185)	126
Dividends paid to parent	**–**	(155)	(203)
Dividends paid on preferred stock	**(2)**	(2)	(2)
Other financing activities	**(2)**	1	2
Net cash provided (used) by financing activities	**282**	(35)	124
Net increase (decrease) in cash and cash equivalents	**206**	2	(6)
Cash and cash equivalents at beginning of year	**12**	10	16
Cash and cash equivalents at end of year	**$ 218**	$ 12	$ 10
Supplemental disclosures of cash flow information			
Cash paid during the year – interest (net of amount capitalized)	**$ 131**	$ 118	$ 104
income taxes (net of refunds)	**$ 185**	$ 57	$ 177

See Notes to PEF Financial Statements.

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA
STATEMENTS of CHANGES in COMMON STOCK EQUITY

(in millions except shares outstanding)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2002	100	$ 1,081	$ (3)	$ 970	$ 2,048
Net income		–	–	297	297
Other comprehensive loss		–	(1)	–	(1)
Comprehensive income					296
Preferred stock dividends at stated rates		–	–	(2)	(2)
Dividends paid to parent		–	–	(203)	(203)
Balance, December 31, 2003	100	1,081	(4)	$ 1,062	2,139
Net income		–	–	335	335
Other comprehensive income		–	4	–	4
Comprehensive income					339
Preferred stock dividends at stated rates		–	–	(2)	(2)
Dividends paid to parent		–	–	(155)	(155)
Balance, December 31, 2004	**100**	**1,081**	**–**	**1,240**	**2,321**
Net income		**–**	**–**	**260**	**260**
Comprehensive income					**260**
Stock-based compensation expense		**1**	**–**	**–**	**1**
Noncash contribution from parent		**15**	**–**	**–**	**15**
Preferred stock dividends at stated rates		**–**	**–**	**(2)**	**(2)**
Balance, December 31, 2005	**100**	**$ 1,097**	**$ –**	**$ 1,498**	**$ 2,595**

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA
STATEMENTS of COMPREHENSIVE INCOME

(in millions) Years ended December 31	**2005**	2004	2003
Net income	**$ 260**	$ 335	$ 297
Other comprehensive income (loss)			
Reclassification of minimum pension liability to regulatory assets (net of tax expense of $2)	–	4	–
Minimum pension liability adjustment (net of tax benefit of $1)	–	–	(1)
Other comprehensive income (loss)	–	4	(1)
Comprehensive income	**$ 260**	$ 339	$ 296

See Notes to PEF Financial Statements.

COMBINED NOTES TO FINANCIAL STATEMENTS

In this report, Progress Energy [which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis] is at times referred to as "we," "us" or "our." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. The information in these combined notes relates to each of the Progress Registrants as noted in the Index to the Combined Notes. However, neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

Progress Energy, Inc.

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

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

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

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

PEC

PEC is a public service corporation primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. PEC's subsidiaries are involved in insignificant nonregulated business activities. PEC is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC), the FERC as well as the provisions of PUHCA prior to February 8, 2006 due to PEC being a wholly owned subsidiary of Progress Energy.

PEF

PEF is a public service corporation primarily engaged in the generation, transmission, distribution and sale of electricity in west central Florida. PEF is subject to the regulatory provisions of the Florida Public Service

Commission (FPSC), the NRC, the FERC as well as the provisions of PUHCA prior to February 8, 2006 due to PEF being a wholly owned subsidiary of Progress Energy.

B. Basis of Presentation

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

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies (generally 20 to 50 percent ownership), are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 21). Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 13 for more information about our investments.

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

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

These combined notes accompany and form an integral part of Progress Energy's and PEC's consolidated financial statements and PEF's financial statements.

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

C. Consolidation of Variable Interest Entities

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

<u>Progress Energy</u>

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

PEC

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

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC and PEC has applied the information scope exception in FIN No. 46R, paragraph 4(g), to the 17 partnerships. PEC has no direct exposure to loss from the 17 partnerships; PEC's only exposure to loss is from its investment of less than $1 million in the consolidated limited partnership. PEC will continue its efforts to obtain the necessary information to fully apply FIN No. 46R to the 17 partnerships. PEC 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 PEC's Consolidated Balance Sheets.

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

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

PEF

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

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in electric operating revenues and taxes other than on income in the statements of income for the years ended December 31 were as follows:

(in millions)	**2005**	2004	2003
Progress Energy	**$ 258**	$ 240	$ 217
PEC	**91**	89	81
PEF	**167**	151	136

STOCK-BASED COMPENSATION

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

RELATED PARTY TRANSACTIONS

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

UTILITY PLANT

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

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

ASSET RETIREMENT OBLIGATIONS

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

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

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

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

CASH AND CASH EQUIVALENTS

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

INVENTORY

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

REGULATORY ASSETS AND LIABILITIES

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

DIVERSIFIED BUSINESS PROPERTY

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

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

GOODWILL AND INTANGIBLE ASSETS

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

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 lives using the straight-line method consistent with ratemaking treatment (See Note 7A).

INCOME TAXES

We and our affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to PEC 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 carryover of uncompensated tax benefits, which primarily relate to deferred synthetic fuel tax credits. Since 2002, Progress Energy tax benefits not related to acquisition interest expense have been allocated to profitable subsidiaries in accordance with a PUHCA order. Except for the allocation of these Progress Energy tax benefits, income taxes are provided as if PEC and PEF filed separate returns. Due to the repeal of PUHCA, effective February 8, 2006, we will stop allocating these tax benefits.

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

DERIVATIVES

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

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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

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

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

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

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

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

SUBSIDIARY STOCK TRANSACTIONS

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

2. NEW ACCOUNTING STANDARDS

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

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

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

FASB INTERPRETATION NO. 47, "ACCOUNTING FOR CONDITIONAL ASSET RETIREMENT OBLIGATIONS"

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

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

The following table summarizes the effect of the implementation of FIN No. 47 on the financial statements of Progress Energy, PEC and PEF as of December 31, 2005.

(in millions)	ARO Liability	Net Asset Retirement Cost	Net Regulatory Asset/(Liability)
Progress Energy	$ 50	$ 15	$ (8)
PEC	23	5	2
PEF	27	4	(4)

Asbestos abatement costs previously included in regulatory liabilities were reclassified upon implementation of FIN No. 47 and included in the calculation of these AROs at December 31, 2005. The amounts reclassified were $16 million and $27 million for PEC and PEF, respectively, for a cumulative total of $43 million for Progress Energy.

3. DIVESTITURES

A. Coal Mines Divestiture

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

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

B. Progress Rail Divestiture

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

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

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

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

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

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

C. Net Assets of Discontinued Operations

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

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

D. Divestiture of Winter Park Distribution Assets

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

E. Sale of Natural Gas Assets

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

F. Divestiture of Synthetic Fuel Partnership Interests

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

G. Mesa Hydrocarbons, Inc., Divestiture

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

H. NCNG Divestiture

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

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

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

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

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

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

4. ACQUISITIONS AND BUSINESS COMBINATIONS

A. Acquisition of Natural Gas Reserves - 2005

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in approximately 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent (Bcf) from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves. The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005, 2004 or 2003.

B. Progress Telecommunications Corporation Transaction

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

The transaction was accounted for as a partial acquisition of EPIK through the issuance of the stock of a consolidated subsidiary. The contributions of PTC's and Caronet's net assets were recorded at their carrying values of approximately $31 million. EPIK's contribution was recorded at its estimated fair value of $22 million using the purchase method. No gain or loss was recognized on the transaction. The EPIK purchase price was initially allocated as follows: property and equipment – $27 million; other current assets – $9 million; current liabilities – $21 million; and goodwill – $7 million. During 2004, PT LLC developed a restructuring plan to exit 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.

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

C. Acquisition of Natural Gas Reserves - 2003

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

D. Acquisition of Wholesale Energy Contract

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

5. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

	Depreciable	Progress Energy		PEC		PEF	
(in millions)	Lives	**2005**	2004	**2005**	2004	**2005**	2004
Production plant	7-33	**$ 12,470**	$ 11,966	**$ 8,241**	$ 7,954	**$ 4,039**	$ 3,818
Transmission plant	30-75	**2,353**	2,282	**1,264**	1,212	**1,089**	1,070
Distribution plant	12-50	**7,015**	6,749	**3,838**	3,701	**3,177**	3,047
General plant and other	8-75	**1,102**	1,106	**651**	654	**451**	452
Utility plant in service		**$ 22,940**	$ 22,103	**$ 13,994**	$ 13,521	**$ 8,756**	$ 8,387

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

AFUDC represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 5.6% in 2005, 7.2% in 2004 and 4.0% in 2003, respectively. The composite AFUDC rate for PEF's electric utility plant was 7.8% in 2005, 2004 and 2003.

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

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

PEC's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.7% in 2005, 2.1% in 2004, and 2.7% in 2003. The depreciation provisions related to utility plant were $365 million, $275 million and $345 million in 2005, 2004 and 2003, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Note 7) and Clean Smokestacks Act amortization (See Note 7B).

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

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.3% in 2005, 2004 and 2003. The depreciation provisions related to utility plant were $191 million, $188 million and $172 million in 2005, 2004 and 2003, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Notes 7 and 22).

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

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2005, 2004 and 2003 was $109 million, $106 million and $112 million, respectively, for PEC and $31 million, $34 million and $31 million, respectively, for PEF. These costs were included in fuel used for electric generation in the Statements of Income.

B. Diversified Business Property

Progress Energy

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

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

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

PEC

Net diversified business property was $7 million at both December 31, 2005 and 2004. These amounts consist primarily of buildings and equipment that are being depreciated over periods ranging from 10 to 40 years. Accumulated depreciation was $2 million at both December 31, 2005 and 2004. Diversified business depreciation expense was less than $1 million in both 2005 and 2004 and $1 million in 2003. Net diversified business property is included in miscellaneous other property and investments on the Consolidated Balance Sheets.

C. Joint Ownership of Generating Facilities

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

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

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

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

D. Asset Retirement Obligations

At December 31, 2005 and 2004, the asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $31 million and $46 million, respectively, for PEC and $36 million at December 31, 2004 for PEF. No costs related to nuclear decommissioning of irradiated plant were recorded in 2005 at PEF. At December 31, 2005 and 2004, additional PEF-related asset retirement costs, net of accumulated depreciation, of $137 million and $193 million, respectively, were recorded at Progress Energy. Funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $640 million and $580 million at December 31, 2005 and 2004, respectively, for PEC and $493 million and $464 million, respectively, for PEF. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

PEC's decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million in 2005, 2004 and 2003. Management believes that decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset retirement obligations, which are included in depreciation and amortization expense, were $90 million, $83 million and $86 million in 2005, 2004 and 2003, respectively, for PEC and $78 million, $77 million and $72 million in 2005, 2004 and 2003, respectively, for PEF.

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Removal costs	**$ 1,316**	$ 1,606	**$ 661**	$ 601	**$ 655**	$ 1,005
Nonirradiated decommissioning costs	**132**	131	**71**	70	**61**	61
Dismantlement costs	**123**	144	**–**	–	**123**	144
Non-ARO cost of removal	**$ 1,571**	$ 1,881	**$ 732**	$ 671	**$ 839**	$ 1,210

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

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

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

Settlement continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN No. 47 as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 2).

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

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

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

	Progress Energy			
(in millions)	Regulated	Nonregulated	PEC	PEF
Asset retirement obligations at January 1, 2004	$ 1,251	$ 5	$ 932	$ 319
Additions	–	1	–	–
Accretion expense	73	–	55	18
Revisions to prior estimates	(63)	(2)	(63)	–
Asset retirement obligations at December 31, 2004	1,261	4	924	337
Additions	**50**	**6**	**23**	**27**
Accretion expense	**65**	**–**	**51**	**14**
Revisions to prior estimates	**(137)**	**–**	**(49)**	**(88)**
Asset retirement obligations at December 31, 2005	**$ 1,239**	**$ 10**	**$ 949**	**$ 290**

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

E. Insurance

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

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

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

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

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

6. CURRENT ASSETS

A. Receivables

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Trade accounts receivable	**$ 713**	$ 499	**$ 336**	$ 240	**$ 263**	$ 195
Unbilled accounts receivable	**282**	271	**158**	155	**60**	66
Notes receivable	**76**	97	**–**	–	**–**	–
Other receivables	**45**	23	**28**	12	**14**	7
Unbilled other receivables	**6**	28	**–**	–	**–**	–
Allowance for doubtful accounts receivable	**(19)**	(22)	**(4)**	(10)	**(6)**	(2)
Total receivables	**$ 1,103**	$ 896	**$ 518**	$ 397	**$ 331**	$ 266

B. Inventory

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Fuel for production	**$ 329**	$ 235	**$ 185**	$ 127	**$ 136**	**$ 104**
Inventory for sale	**61**	49	**–**	–	**–**	–
Materials and supplies	**441**	517	**240**	263	**166**	176
Emission allowances	**35**	21	**26**	11	**9**	10
Total current inventory	**$ 866**	$ 822	**$ 451**	$ 401	**$ 311**	$ 290

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

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits for Progress Energy, PEC and PEF of $14 million, $13 million, and $1 million, respectively, at December 31, 2005 and none at December 31, 2004.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

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

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

Progress Energy

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

PEC

(in millions)	**2005**	2004
Deferred fuel cost – current (Note 7B)	**$ 261**	$ 140
Deferred fuel cost – long-term (Note 7B)	**31**	28
Deferred impact of ARO (Note 1D)	**281**	305
Income taxes recoverable through future rates (Note 14)	**22**	36
Loss on reacquired debt (Note 1D)	**21**	22
Storm deferral (Note 7B)	**19**	25
Other	**47**	57
Total long-term regulatory assets	**421**	473
Non-ARO cost of removal (Note 5D)	**(732)**	(671)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(135)**	(125)
Clean Smokestacks Act compliance (Note 7B)	**(317)**	(248)
Other	**(12)**	(8)
Total long-term regulatory liabilities	**(1,196)**	(1,052)
Net regulatory liabilities	**$ (514)**	$ (439)

PEF

(in millions)	**2005**	2004
Deferred fuel cost - current (Note 7C)	**$ 341**	$ 89
Deferred fuel cost – long-term (Note 7C)	**–**	79
Storm deferral (Note 7C)	**208**	291
Income taxes recoverable through future rates (Note 14)	**59**	49
Loss on reacquired debt (Note 1D)	**29**	31
Postretirement benefits	**7**	7
Other	**48**	67
Total long-term regulatory assets	**351**	524
Deferred energy conservation cost - current	**(10)**	(8)
Non-ARO cost of removal (Note 5D)	**(839)**	(1,210)
Deferred impact of ARO (Note 1D)	**(80)**	(26)
Net nuclear decommissioning trust unrealized gains (Note 5D)	**(116)**	(99)
Derivative mark-to-market adjustment (Note 18A)	**(122)**	(2)
Other	**(32)**	(25)
Total long-term regulatory liabilities	**(1,189)**	(1,362)
Net regulatory liabilities	**$ (507)**	$ (757)

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

B. PEC Retail Rate Matters

FUEL COST RECOVERY

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

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

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

STORM COST RECOVERY

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

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

OTHER MATTERS

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

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

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

C. PEF Retail Rate Matters

STORM COST RECOVERY

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

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

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

PASS-THROUGH CLAUSE COST RECOVERY

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

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

BASE RATE SETTLEMENT

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

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

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

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

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

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

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

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

FRANCHISE MATTERS

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

OTHER MATTERS

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

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

D. Regional Transmission Organizations

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

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

E. FERC Market Power Mitigation

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

F. Energy Delivery Capitalization Practice

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

8. GOODWILL AND OTHER INTANGIBLE ASSETS

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

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

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

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

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

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

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

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

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

PEC had intangible assets related to minimum pension liability adjustments of $17 million and $18 million at December 31, 2005 and 2004, respectively. PEF had intangible assets related to minimum pension liability adjustments of $2 million at December 31, 2005.

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

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. In 2005 and 2003, we recorded pre-tax long-lived asset and investment impairments and other charges of $1 million and $38 million, respectively. PEC recorded pre-tax long-lived asset and investment impairments and other charges of $1 million and $21 million, respectively, in 2005 and 2003. No impairments were recorded in 2004.

A. Long-Lived Assets

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

B. Investments

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

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

10. EQUITY

A. Common Stock

Progress Energy

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

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

PEC

At December 31, 2005 and 2004, PEC was authorized to issue up to 200 million shares of common stock. All shares issued and outstanding are held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2005, there were no significant restrictions on the use of retained earnings. See Note 12 for additional dividend restrictions related to PEC.

PEF

At December 31, 2005 and 2004, PEF was authorized to issue up to 60 million shares of common stock. All PEF common shares issued and outstanding are indirectly held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2005, there were no significant restrictions on the use of retained earnings. See Note 12 for additional dividend restrictions related to PEF.

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. Participating subsidiaries as of January

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

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

PEC

PEC's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $11 million, $12 million and $11 million for the years ended December 31, 2005, 2004 and 2003, respectively. Matching and incentive costs totaled approximately $17 million, $18 million and $16 million for the years ended December 31, 2005, 2004 and 2003, respectively.

PEF

PEF's matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $4 million, $5 million and $4 million for the years ended December 31, 2005, 2004 and 2003, respectively. Matching and incentive costs totaled approximately $6 million, $7 million and $10 million for the years ended December 31, 2005, 2004 and 2003, respectively.

NEW ACCOUNTING FOR STOCK-BASED COMPENSATION

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

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

Progress Energy

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

PEC

PEC participates in the Progress Energy stock option and other stock-based compensation plans and its adoption of SFAS No. 123R resulted in the recognition of approximately $1 million of pre-tax expense for stock options for the year ended December 31, 2005, which would not have been recognized under the prior accounting treatment. Additionally, PEC recognized an immaterial amount of cumulative pre-tax benefit from the accounting change which reflects the cumulative impact of estimating forfeitures in the determination of period expense for other stock-based compensation plans, rather than recording the effect of forfeitures as they occur. The adoption of SFAS No. 123R did not have a material impact on PEC's income or PEC's presentation of cash flows for the year ended December 31, 2005.

PEF

PEF participates in the Progress Energy stock option and other stock-based compensation plans and its adoption of SFAS No. 123R resulted in the recognition of approximately $1 million of pre-tax expense for stock options for the year ended December 31, 2005, which would not have been recognized under the prior accounting treatment. Additionally, PEF recognized an immaterial amount of cumulative pre-tax benefit from the accounting change which reflects the cumulative impact of estimating forfeitures in the determination of period expense for other stock-based compensation plans, rather than recording the effect of forfeitures as they occur. The adoption of SFAS No. 123R did not have a material impact on PEF's income or PEF's presentation of cash flows for the year ended December 31, 2005.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, we may grant options to purchase shares of Progress Energy 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 percent vesting at the end of year three, while options granted to directors vest 100 percent at the end of one year. The options expire 10 years from the date of grant. All option grants have an exercise price equal to the fair market value of our common stock on the grant date. As noted above, we have ceased granting stock options. An immaterial number of stock options were granted in 2004 and no stock options have been granted in 2005. We issue new shares of common stock to satisfy the exercise of previously issued stock options.

Progress Energy

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

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

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

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

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

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

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

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

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

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

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

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

PEC

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. At December 31, 2005, there was $1 million of total unrecognized compensation cost related to nonvested stock options which will be recognized over one year.

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

(in millions)	**2005**	2004	2003
Net income, as reported	**$493**	$461	$482
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**2**	7	6
Pro forma net income	**$491**	$454	$476

PEF

Stock option expense totaling $1 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of less than $1 million. No compensation cost related to stock options was capitalized during the year. At December 31, 2005, there was less than $1 million of total unrecognized compensation cost related to nonvested stock options which will be recognized over one year.

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

(in millions)	**2005**	2004	2003
Net income, as reported	**$260**	$335	$297
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**1**	2	2
Pro forma net income	**$259**	$333	$295

OTHER STOCK-BASED COMPENSATION PLANS

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

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

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

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

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

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

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

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

PEC

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $7 million for the year ended December 31, 2005, with a recognized tax benefit of $3 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $7 million for the year ended December 31, 2004, with a recognized tax benefit of $3 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $15 million for the year ended December 31, 2003, with a recognized tax benefit of $6 million. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

Our Statements of Income included total recognized expense for other stock-based compensation plans of $3 million for the year ended December 31, 2005, with a recognized tax benefit of $1 million. The total expense recognized on our Statements of Income for other stock-based compensation plans was $2 million for the year ended December 31, 2004, with a recognized tax benefit of $1 million. The total expense recognized on our Statements of Income for other stock-based compensation plans was $7 million for the year ended December 31, 2003, with a recognized tax benefit of $3 million. No compensation cost related to other stock-based compensation plans was capitalized.

C. Earnings Per Common Share

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

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

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

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

D. Accumulated Other Comprehensive Loss

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

	Progress Energy		PEC	
(in millions)	**2005**	2004	**2005**	2004
Gain (loss) on cash flow hedges	**$ 55**	$ (28)	$ (3)	$ (7)
Minimum pension liability adjustments	**(160)**	(142)	(119)	(107)
Foreign currency translation and other	**1**	6	2	–
Total accumulated other comprehensive loss	**$ (104)**	$ (164)	$ (120)	$ (114)

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

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

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

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

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

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

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

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

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

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

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

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

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

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

(in millions)	Progress Energy Consolidated	PEC	PEF
2006	$ 513	$ –	$ 48
2007	674	200	89
2008	1,277	300	532
2009	401	400	–
2010	406	6	300
Thereafter	7,781	2,785	1,641
Total	$ 11,052	$ 3,691	$ 2,610

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

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

B. Covenants and Default Provisions

FINANCIAL COVENANTS

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

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

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

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

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

MATERIAL ADVERSE CHANGE CLAUSE

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

CROSS-DEFAULT PROVISIONS

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

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

OTHER RESTRICTIONS

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

PEC

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

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

PEF

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

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

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

C. Collateralized Obligations

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

D. Guarantees of Subsidiary Debt

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

E. Hedging Activities

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

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. Investments

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Nuclear decommissioning trust (See Note 5D)	**$ 1,133**	$ 1,044	**$ 640**	$ 581	**$ 493**	$ 463
Investments in equity securities (a)	**7**	3	**6**	3	**1**	–
Equity method investments (b)	**27**	26	**15**	15	**–**	–
Cost investments (c)	**13**	14	**1**	1	**–**	–
Benefit investment trusts (d)	**77**	76	**1**	1	**–**	–
Company-owned life insurance (d)	**153**	145	**97**	93	**39**	34
Marketable debt securities (e)	**191**	82	**191**	82	**–**	–
Total	**$ 1,601**	$ 1,390	**$ 951**	$ 776	**$ 533**	$ 497

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

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

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

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

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

B. Fair Value of Financial Instruments

Progress Energy

DEBT

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

INVESTMENTS

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

2005 (in millions)	**Book Value**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Equity securities	**$ 411**	**$ 257**	**$ 5**	**$ 663**
Debt securities	**680**	**7**	**7**	**680**
Cash equivalents	**18**	**–**	**–**	**18**
Total	**$ 1,109**	**$ 264**	**$ 12**	**$ 1,361**

2004 (in millions)	Book Value	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity securities	$ 387	$ 219	$ 6	$ 600
Debt securities	538	12	2	548
Cash equivalents	17	–	–	17
Total	$ 942	$ 231	$ 8	$ 1,165

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

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

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

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

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

2005	**12 Months or Less**		**Greater than 12 Months**		**Total**	
(in millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Equity securities	**$ 653**	**$ 3**	**$ 10**	**$ 2**	**$ 663**	**$ 5**
Debt securities	**653**	**7**	**27**	**–**	**680**	**7**
Cash equivalents	**18**	**–**	**–**	**–**	**18**	**–**
Total	**$ 1,324**	**$ 10**	**$ 37**	**$ 2**	**$ 1,361**	**$ 12**

2004	12 Months or Less		Greater than 12 Months		Total	
(in millions)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Equity securities	$ 587	$ 3	$ 13	$ 3	$ 600	$ 6
Debt securities	546	2	2	–	548	2
Cash equivalents	17	–	–	–	17	–
Total	$ 1,150	$ 5	$ 15	$ 3	$ 1,165	$ 8

PEC

DEBT

The carrying amount of PEC's long-term debt, including current maturities, was $3.667 billion and $3.050 billion at December 31, 2005 and 2004, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3.789 billion and $3.307 billion at December 31, 2005 and 2004, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust fund, PEC holds other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. PEC's available-for-sale securities at December 31, 2005 and 2004 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2005				
(in millions)	**Book Value**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Equity securities	**$ 222**	**$ 141**	**$ 4**	**$ 359**
Debt securities	**465**	**4**	**4**	**465**
Cash equivalents	**10**	**–**	**–**	**10**
Total	**$ 697**	**$ 145**	**$ 8**	**$ 834**

2004				
(in millions)	Book Value	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity securities	$ 208	$ 123	$ 5	$ 326
Debt securities	319	7	1	325
Cash equivalents	12	–	–	12
Total	$ 539	$ 130	$ 6	$ 663

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

Due in one year or less	$ 4
Due after one through five years	78
Due after five through 10 years	80
Due after 10 years	303
Total	$ 465

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

(in millions)	**2005**	2004	2003
Proceeds	**$ 1,678**	$ 2,584	$ 2,990
Realized gains	**13**	24	10
Realized losses	**8**	20	12

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

2005	**12 Months Or Less**		**Greater Than 12 Months**		**Total**	
(in millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Equity securities	**$ 349**	**$ 2**	**$ 10**	**$ 2**	**$ 359**	**$ 4**
Debt securities	**451**	**4**	**14**	**–**	**465**	**4**
Cash equivalents	**10**	**–**	**–**	**–**	**10**	**–**
Total	**$ 810**	**$ 6**	**$ 24**	**$ 2**	**$ 834**	**$ 8**

2004	12 Months Or Less		Greater Than 12 Months		Total	
(in millions)	Fair Value	Unrealized Losses	Fair value	Unrealized Losses	Fair Value	Unrealized Losses
Equity securities	$ 315	$ 2	$ 11	$ 3	$ 326	$ 5
Debt securities	323	1	2	–	325	1
Cash equivalents	12	–	–	–	12	–
Total	$ 650	$ 3	$ 13	$ 3	$ 663	$ 6

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $2.602 billion and $1.960 billion at December 31, 2005 and 2004, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2.635 billion and $2.080 billion at December 31, 2005 and 2004, respectively.

INVESTMENTS

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 5D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents and are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. PEF's available-for-sale securities at December 31, 2005 and 2004 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2005				
(in millions)	**Book Value**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Equity securities	**$ 189**	**$ 116**	**$ 1**	**$ 304**
Debt securities	**182**	**3**	**2**	**183**
Cash equivalents	**5**	**–**	**–**	**5**
Total	**$ 376**	**$ 119**	**$ 3**	**$ 492**

2004				
(in millions)	Book Value	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity securities	$ 179	$ 96	$ 1	$ 274
Debt securities	183	5	1	187
Cash equivalents	5	–	–	5
Total	$ 367	$ 101	$ 2	$ 466

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

Due in one year or less	$ 3
Due after one through five years	53
Due after five through 10 years	54
Due after 10 years	73
Total	$ 183

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

(in millions)	**2005**	2004	2003
Proceeds	**$330**	$529	$295
Realized gains	**13**	30	10
Realized losses	**10**	3	12

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

2005	**12 Months Or Less**		**Greater Than 12 Months**		**Total**	
(in millions)	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
Equity securities	**$ 304**	**$ 1**	**$ –**	**$ –**	**$ 304**	**$ 1**
Debt securities	**173**	**2**	**10**	**–**	**183**	**2**
Cash equivalents	**5**	**–**	**–**	**–**	**5**	**–**
Total	**$ 482**	**$ 3**	**$ 10**	**$ –**	**$ 492**	**$ 3**

2004	12 Months Or Less		Greater Than 12 Months		Total	
(in millions)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Equity securities	$ 272	$ 1	$ 2	$ –	$ 274	$ 1
Debt securities	187	1	–	–	187	1
Cash equivalents	5	–	–	–	5	–
Total	$ 464	$ 2	$ 2	$ –	$ 466	$ 2

14. INCOME TAXES

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

Progress Energy

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- Less than $1 million of deferred tax expense and $16 million of deferred tax benefit related to the cumulative effect of changes in accounting principle recorded net of tax during 2005 and 2003, respectively. There was no cumulative effect of changes in accounting principle recorded during 2004.

- Taxes related to discontinued operations recorded net of tax for 2005, 2004 and 2003, which are presented separately in Notes 3A and 3B.

- Taxes related to other comprehensive income recorded net of tax for 2005, 2004 and 2003, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $2 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004. There was no amount recorded in common stock for excess tax deductions during 2003.

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

PEC

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

(in millions)	**2005**	2004
Deferred income tax assets:		
Asset retirement obligation liability	**$ 131**	$ 137
Compensation accruals	**46**	49
Deferred revenue	**55**	-
Income taxes refundable through future rates	**54**	49
Postretirement and pension benefits	**155**	136
Other	**49**	80
Federal income tax credit carry forward	**20**	20
Total deferred income tax assets	**510**	471
Deferred income tax liabilities:		
Accumulated depreciation and property cost differences	**(952)**	(1,037)
Deferred fuel recovery	**(67)**	(54)
Income taxes recoverable through future rates	**(129)**	(134)
Investments	**(61)**	(59)
Other	**(27)**	(39)
Total deferred income tax liabilities	**(1,236)**	(1,323)
Total net deferred income tax liabilities	**$ (726)**	$ (852)

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

(in millions)	**2005**	2004
Current deferred income tax assets, included in prepayments and other current assets	**$ –**	$ 36
Current deferred income tax liabilities, included in other current liabilities	**(4)**	–
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(722)**	(888)
Total net deferred income tax liabilities	**$ (726)**	$ (852)

Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2005 and 2004 include $92 million and $103 million, respectively, related to probable tax liabilities, on which PEC accrues interest that would be payable with the related tax amount in future years.

At December 31, 2005, the federal income tax credit carry forward includes $20 million of general business credits that will expire during the period 2022 through 2025.

At December 31, 2005 and 2004, PEC had recorded $2 million and less than $1 million, respectively, of tax contingency reserves, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

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

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

	2005	2004	2003
Effective income tax rate	**32.7%**	34.1%	32.3%
State income taxes, net of federal benefit	**(2.1)**	(2.9)	(1.9)
Investment tax credit amortization	**1.1**	1.1	1.4
Domestic manufacturing deduction	**0.7**	–	–
Progress Energy tax benefit allocation	**2.9**	3.0	3.0
Other differences, net	**(0.3)**	(0.3)	0.2
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2005**	2004	2003
Current – federal	**$ 343**	$ 232	$ 283
– state	**45**	33	37
Deferred – federal	**(120)**	(18)	(56)
– state	**(21)**	(1)	(13)
Investment tax credit	**(8)**	(7)	(10)
Total income tax expense	**$ 239**	$ 239	$ 241

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

- Less than $1 million of deferred tax expense and $15 million of deferred tax benefit related to the cumulative effect of changes in accounting principle recorded net of tax during 2005 and 2003, respectively. There was no cumulative effect of changes in accounting principle recorded during 2004.

- Taxes related to other comprehensive income recorded net of tax for 2005, 2004 and 2003, which are presented separately in the Consolidated Statements of Comprehensive Income.

- Current tax benefit of $1 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004. There was no amount recorded in common stock for excess tax deductions during 2003.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with Progress Energy (See Note 1D). PEC's intercompany tax payable was approximately $74 million at December 31, 2005. PEC's intercompany tax receivable was approximately $62 million at December 31, 2004.

PEF

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

(in millions)	**2005**	2004
Deferred income tax assets		
Asset retirement obligation liability	**$ 3**	$ 32
Income taxes refundable through future rates	**123**	49
Postretirement and pension benefits	**85**	78
Unbilled revenue	**30**	35
Other	**68**	85
Total deferred income tax assets	**309**	279
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(401)**	(403)
Deferred fuel recovery	**(21)**	(13)
Deferred storm costs	**(87)**	(131)
Derivative instruments	**(45)**	(1)
Income taxes recoverable through future rates	**(28)**	(21)
Investments	**(45)**	(38)
Prepaid pension costs	**(61)**	(89)
Other	**(25)**	(30)
Total deferred income tax liabilities	**(713)**	(726)
Total net deferred income tax liabilities	**$ (404)**	$ (447)

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

(in millions)	**2005**	2004
Current deferred income tax assets	**$ 12**	$ 42
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(416)**	(489)
Total net deferred income tax liabilities	**$ (404)**	$ (447)

Total noncurrent income tax liabilities on the Balance Sheets at December 31, 2005 and 2004, include $17 million and less than $1 million, respectively, related to probable tax liabilities on which PEF accrues interest that would be payable with the related tax amount in future years.

At December 31, 2005 and 2004, PEF had recorded $7 million of tax contingency reserves, excluding accrued interest and penalties, which were included in other current liabilities on the Balance Sheets.

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

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

	2005	2004	2003
Effective income tax rate	**31.8%**	34.2%	33.1%
State income taxes, net of federal benefit	**(3.3)**	(3.5)	(3.5)
Investment tax credit amortization	**1.4**	1.2	1.4
Domestic manufacturing deduction	**0.9**	–	–
Progress Energy tax allocation benefit	**3.2**	2.5	2.7
Other differences, net	**1.0**	0.6	1.3
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

(in millions)	**2005**	2004	2003
Current – federal	**$ 146**	$ 55	$ 145
– state	**25**	9	27
Deferred – federal	**(39)**	98	(16)
– state	**(6)**	18	(3)
Investment tax credit	**(5)**	(6)	(6)
Total income tax expense (benefit)	**$ 121**	$ 174	$ 147

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

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2004 or 2003.

- Taxes related to other comprehensive income recorded net of tax for 2005, 2004 and 2003, which are presented separately in the Statements of Comprehensive Income.

- Less than $1 million of current tax benefit related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005 and 2004. There was no amount recorded in common stock for excess tax deductions during 2003.

PEF has entered into the Tax Agreement with Progress Energy (See Note 1D) and its intercompany tax payable was approximately $7 million and $21 million at December 31, 2005 and 2004, respectively.

15. CONTINGENT VALUE OBLIGATIONS

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

16. BENEFIT PLANS

A. Postretirement Benefits

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

COSTS OF BENEFIT PLANS

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

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

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

Progress Energy

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

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

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

PEC

(in millions)	Pension Benefits **2005**	2004	2003	Other Postretirement Benefits **2005**	2004	2003
Service cost	**$ 22**	$ 24	$ 23	**$ 4**	$ 6	$ 7
Interest cost	**53**	52	51	**17**	15	15
Expected return on plan assets	**(62)**	(69)	(70)	**(4)**	(4)	(3)
Amortization of actuarial loss	**10**	1	–	**5**	2	2
Other amortization, net	**1**	–	–	**1**	1	3
Net periodic cost	**$ 24**	$ 8	$ 4	**$ 23**	$ 20	$ 24

In addition to the net periodic cost reflected above, in 2005, PEC recorded costs for special termination benefits related to the voluntary enhanced retirement program (See Note 17) of $21 million for pension benefits and $8 million for other postretirement benefits.

PEF

(in millions)	Pension Benefits **2005**	2004	2003	Other Postretirement Benefits **2005**	2004	2003
Service cost	**$ 16**	$ 21	$ 19	**$ 3**	$ 4	$ 5
Interest cost	**48**	43	41	**13**	13	15
Expected return on plan assets	**(73)**	(73)	(58)	**(1)**	(1)	(1)
Amortization of actuarial loss	**8**	2	5	**2**	1	1
Other amortization, net	**(1)**	(1)	(2)	**4**	4	4
Net periodic cost (benefit)	**$ (2)**	$ (8)	$ 5	**$ 21**	$ 21	$ 24

In addition to the net periodic cost and benefit reflected above, in 2005 PEF recorded costs for special termination benefits related to the voluntary enhanced retirement program (See Note 17) of $84 million for pension benefits and $7 million for other postretirement benefits.

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

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

The weighted-average actuarial assumptions used by PEC and PEF were not materially different from the assumptions above, as applicable, except that the expected long-term rate of return on PEF's OPEB plan assets was 5.0% for all years presented.

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 Progress Registrants have chosen to use an expected long-term rate of 9.0%, the low end of the range, beginning in 2005.

PREPAID/ACCRUED BENEFIT COSTS

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

Progress Energy

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

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

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

PEC

(in millions)	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Obligation at January 1	**$ 928**	$ 837	**$ 262**	$ 218
Service cost	**22**	24	**4**	6
Interest cost	**53**	52	**17**	15
Plan amendment	–	14	–	–
Benefit payments	**(94)**	(50)	**(14)**	(5)
Actuarial loss (gain)	**39**	51	**56**	28
Special termination benefits	**21**	–	**8**	–
Obligation at December 31	**969**	928	**333**	262
Fair value of plan assets at December 31	**731**	753	**49**	45
Funded status	**(238)**	(175)	**(284)**	(217)
Unrecognized transition obligation	–	–	**8**	9
Unrecognized prior service cost	**17**	18	–	–
Unrecognized net actuarial (gain) loss	**201**	181	**87**	36
Minimum pension liability adjustment	**(212)**	(194)	–	–
Accrued cost at December 31, net	**$ (232)**	$ (170)	**$ (189)**	$ (172)

The net accrued pension cost of $232 and $170 million at December 31, 2005 and 2004, respectively, is included in accrued pension and other benefits in the Consolidated Balance Sheets. The defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $969 and $928 million at December 31, 2005 and 2004, respectively. Those plans had accumulated benefit obligations totaling $963 and $923 million, at December 31, 2005 and 2004, respectively, and plan assets of $731 and $753 million at December 31, 2005 and 2004, respectively. The total accumulated benefit obligation for pension plans was $963 and $923 million at December 31, 2005 and 2004, respectively. The accrued OPEB cost is included in accrued pension and other benefits in the Consolidated Balance Sheets.

A minimum pension liability adjustment of $212 million was recorded at December 31, 2005. This adjustment resulted in a charge of $17 million to intangible assets, included in other assets and deferred debits, and a pre-tax charge of $195 million to accumulated other comprehensive loss, a component of common stock equity. A minimum pension liability adjustment of $194 million was recorded at December 31, 2004. This adjustment resulted in a charge of $18 million to intangible assets, included in other assets and deferred debits, and a pre-tax charge of $176 million to accumulated other comprehensive loss, a component of common stock equity.

PEF

(in millions)	Pension Benefits 2005	2004	Other Postretirement Benefits 2005	2004
Obligation at January 1	**$ 767**	$ 701	**$ 232**	$ 217
Service cost	**16**	21	**3**	4
Interest cost	**48**	43	**13**	13
Plan amendment	**–**	2	**–**	–
Benefit payments	**(61)**	(37)	**(18)**	(17)
Special termination benefits	**85**	–	**7**	–
Actuarial loss (gain)	**41**	37	**22**	15
Obligation at December 31	**896**	767	**259**	232
Fair value of plan assets at December 31	**895**	868	**22**	20
Funded status	**(1)**	101	**(237)**	(212)
Unrecognized transition obligation	**–**	–	**24**	27
Unrecognized prior service cost (benefit)	**(12)**	(14)	**5**	6
Unrecognized net actuarial (gain) loss	**132**	112	**49**	29
Minimum pension liability adjustment	**(8)**	(7)	**–**	–
Prepaid (accrued) cost at December 31, net	**$ 111**	$ 192	**$ (159)**	$ (150)

The PEF net prepaid pension cost of $111 and $192 million at December 31, 2005 and 2004, respectively, is included in the Balance Sheets as prepaid pension cost of $200 million and $234 million, respectively, and accrued benefit cost of $89 million and $42 million, respectively, which is included in accrued pension and other benefits. The PEF defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $341 and $41 million at December 31, 2005 and 2004, respectively. Those plans had accumulated benefit obligations totaling $306 million and $39 million, respectively, and plan assets of $217 million at December 31, 2005, and no plan assets at December 31, 2004. PEF's total accumulated benefit obligation for pension plans was $860 million and $718 million at December 31, 2005 and 2004, respectively. Accrued other postretirement benefit cost is included in accrued pension and other benefits in PEF's Balance Sheets.

PEF recorded a minimum pension liability adjustment of $8 million at December 31, 2005. This adjustment resulted in a charge of $1 million to intangible assets, included in other assets and deferred debits, and a charge of $7 million to a regulatory asset. PEF recorded a minimum pension liability adjustment of $7 million at December 31, 2004, with a corresponding charge of $7 million to a regulatory asset.

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

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

The weighted-average actuarial assumptions for PEC and PEF were the same or were not significantly different from those indicated above, as applicable.

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash Balance' Pension Plan." Therefore, effective December 31, 2003, we began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

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

(in millions)	Progress Energy	PEC	PEF
1 percent increase in medical cost trend rate			
Effect on total of service and interest cost	$ 5	$ 2	$ 2
Effect on postretirement benefit obligation	65	33	26
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(4)	(2)	(2)
Effect on postretirement benefit obligation	(54)	(28)	(22)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, substantially all employer contributions represent benefit payments made directly from the Progress Registrants' assets except for the 2004 pension amount. The remaining benefit payments were made directly from plan assets. In 2004, we made a required contribution of approximately $24 million directly to pension plan assets. In 2004, PEC made a contribution to pension plan assets of approximately $20 million, which represented its allocated share of the required Progress Energy contribution. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the net cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments for Progress Energy, 30 percent for PEC and 10 percent for PEF.

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

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

PEC	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2005**	2004	**2005**	2004
Fair value of plan assets at January 1	**$ 753**	$ 693	**$ 45**	$ 43
Actual return on plan assets	**71**	89	**4**	5
Benefit payments	**(94)**	(50)	**(14)**	(5)
Employer contributions	**1**	21	**14**	2
Fair value of plan assets at December 31	**$ 731**	$ 753	**$ 49**	$ 45

PEF	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2005**	2004	**2005**	2004
Fair value of plan assets at January 1	**$ 868**	$ 802	**$ 20**	$ 18
Actual return on plan assets	**85**	101	**–**	1
Benefit payments	**(61)**	(37)	**(18)**	(17)
Employer contributions	**3**	2	**19**	18
Fair value of plan assets at December 31	**$ 895**	$ 868	**$ 21**	$ 20

The asset allocation for the benefit plans at the end of 2005 and 2004 and the target allocation for the plans, by asset category, are presented in the following tables. The pension benefit plan allocations and targets are consistent for all Progress Registrants.

	Pension Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2006	**2005**	2004
Equity – domestic	40%	**44%**	47%
Equity – international	15%	**22%**	21%
Debt – domestic	20%	**13%**	9%
Debt – international	10%	**8%**	11%
Other	15%	**13%**	12%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
Progress Energy	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2006	**2005**	2004
Equity – domestic	28%	**32%**	34%
Equity – international	11%	**16%**	15%
Debt – domestic	43%	**37%**	35%
Debt – international	7%	**6%**	8%
Other	11%	**9%**	8%
Total	100%	**100%**	100%

PEC	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2006	**2005**	2004
Equity – domestic	40%	**44%**	47%
Equity – international	15%	**22%**	21%
Debt – domestic	20%	**13%**	9%
Debt – international	10%	**8%**	11%
Other	15%	**13%**	12%
Total	100%	**100%**	100%

PEF	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2006	**2005**	2004
Debt – domestic	100%	**100%**	100%

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

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

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

In 2006, PEC expects to make $1 million in contributions directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $79, $56, $58, $62, $64 and $383, respectively. The expected benefit payments for the OPEB plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $19, $20, $21, $22, $23, and $128, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEC assets. The benefit payment amounts reflect the net cost to PEC after any participant contributions. PEC expects to begin receiving prescription drug-related federal subsidies in 2006, and the expected subsidies for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $1, $1, $2, $2, $2 and $15, respectively.

In 2006, PEF expects to make $9 million of 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 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $63, $53, $53, $54, $54 and $295, respectively. The expected benefit payments for the OPEB plan for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $19, $20, $20, $20, $20 and $96, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEF's assets. The benefit payment amounts reflect the net cost to PEF after any participant contributions. PEF expects to begin receiving prescription drug-related federal subsidies in 2006, and the expected subsidies for 2006 through 2010 and in total for 2011 through 2015, in millions, are approximately $1, $2, $2, $2, $2 and $13, respectively.

B. Florida Progress Acquisition

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

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

17. SEVERANCE

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

Progress Energy

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

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

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

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

PEC

In connection with the cost-management initiative, PEC incurred approximately $55 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, as described below.

PEC recorded $14 million of severance expense during the first quarter of 2005 for the workforce restructuring based on the approximate number of positions to be eliminated. This amount included approximately $4 million of severance costs allocated from PESC. During the second quarter of 2005, 553 PEC employees eligible for participation in the voluntary enhanced retirement program elected to participate. Consequently, in the second and fourth quarters of 2005, PEC decreased its estimated severance costs by $6 million and $5 million, respectively, due to the impact of the employees electing participation in the voluntary enhanced retirement program. These amounts included approximately $2 million of decreased severance costs allocated from PESC. The severance expenses are primarily included in O&M expense on the Consolidated Statements of Income.

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

(in millions)	
Balance as of January 1, 2005	$ 2
Severance costs accrued	10
Adjustments	(9)
Payments	(1)
Balance at December 31, 2005	**$ 2**

PEC recorded a $29 million charge in the second quarter of 2005 related to postretirement benefits that will be paid over time to eligible employees who elected to participate in the voluntary enhanced retirement program (See Note 16). PEC also recorded a $13 million charge for early retirement incentives which will be paid over time to certain employees. In addition, PEC recorded approximately $10 million of postretirement benefits and early retirement incentives allocated from PESC during the year ended December 31, 2005.

PEF

In connection with the cost-management initiative, PEF incurred approximately $102 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005, as described below.

PEF recorded $14 million of severance expense during the first quarter of 2005 for the workforce restructuring and implementation of an automated meter reading initiative at PEF based on the approximate number of positions to be eliminated. This amount included approximately $3 million of severance costs allocated from PESC. During the second quarter of 2005, 680 of PEF's employees eligible for participation in the voluntary enhanced retirement program elected to participate. Consequently, in the second and fourth quarters of 2005, PEF decreased its estimated severance costs by $5 million and $6 million, respectively, due to the impact of the employees electing participation in the voluntary enhanced retirement program. These amounts included approximately $2 million of decreased severance costs allocated from PESC. The severance expenses are primarily included in O&M expense on the Statements of Income.

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

(in millions)	
Balance as of January 1, 2005	$ –
Severance costs accrued	11
Adjustments	(9)
Payments	(1)
Balance at December 31, 2005	**$ 1**

During 2005, PEF recorded a $90 million charge in the second quarter and a $1 million charge in the third quarter related to postretirement benefits that will be paid over time to eligible employees who elected to participate in the voluntary enhanced retirement program (See Note 16). In addition, PEF recorded approximately $8 million of charges for postretirement benefits and early retirement incentives allocated from PESC during the year ended December 31, 2005.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

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

A. Commodity Derivatives

GENERAL

Most of our commodity contracts are not derivatives pursuant to SFAS No. 133, "Accounting for Derivative and Hedging Activities" (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.

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

ECONOMIC DERIVATIVES

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

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

CASH FLOW HEDGES

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

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Fair value of assets	**$ 170**	$ –	**$ 7**	$ –	**$ –**	$ –
Fair value of liabilities	**(58)**	(15)	**(4)**	$ –	**$ –**	$ –
Fair value, net	**$ 112**	$ (15)	**$ 3**	$ –	**$ –**	$ –

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

	Maximum Term(a)			Accumulated Other Comprehensive Income/ (Loss), net of Tax			Portion Expected to be Reclassified to Earnings during the Next 12 Months(b)		
(term in years/ millions of dollars)	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF
Commodity cash flow hedges	9	1	–	$ 69	$ 2	$ –	$ (17)	$ 2	$ –

(a) The majority of hedges in fair value liability positions are currently classified as short-term and the majority of hedges in fair value asset positions are currently classified as long-term.
(b) Due to the volatility of the commodities markets, the value in accumulated other comprehensive income/(loss) (OCI) is subject to change prior to its reclassification into earnings.

At December 31, 2004, we had $9 million of after-tax deferred losses in OCI related to commodity cash flow hedges. The Utilities had no open commodity cash flow hedges or amounts recorded in OCI related to commodity cash flow hedges.

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

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

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

	Progress Energy		PEC		PEF	
(in millions)	**2005**	2004	**2005**	2004	**2005**	2004
Interest rate cash flow hedges	**$ 1**	$ (2)	**$ –**	$ (2)	**$ –**	$ –
Interest rate fair value hedges	**$ (2)**	$ 3	**$ –**	**$ –**	**$ –**	$ –

CASH FLOW HEDGES

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

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

	Maximum Term			Accumulated Other Comprehensive Income/ (Loss), net of Tax (a)			Portion Expected to be Reclassified to Earnings during the Next 12 Months (b)		
(term in years/ millions of dollars)	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF	Progress Energy	PEC	PEF
Interest rate cash flow hedges	1	–	–	$ (13)	$ (5)	$ –	$ (2)	$ –	$ –

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

At December 31, 2005 and 2004, we had $100 million notional and $331 million notional, respectively, of interest rate cash flow hedges. The Utilities had no open interest rate cash flow hedges at December 31, 2005. At December 31, 2004, PEC had $131 million notional of open interest rate cash flow hedges and PEF had no open interest rate cash flow hedges.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2005 and 2004, we had $150 million notional of interest rate fair value hedges. At December 31, 2005 and 2004, the Utilities had no open interest rate fair value hedges.

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

19. RELATED PARTY TRANSACTIONS

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

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

PESC provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2005, 2004 and 2003 to PEC amounted to $202 million, $209 million and $184 million, respectively, and services provided to PEF were $169 million, $165 million and $153 million, respectively.

PEC and PEF also provide and receive services at cost. Services provided by PEC to PEF during 2005, 2004 and 2003 amounted to $54 million, $52 million and $35 million, respectively. Services provided by PEF to PEC during 2005, 2004 and 2003 amounted to $14 million, $16 million and $7 million, respectively.

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

PEC and PEF participate in an internal money pool, operated by Progress Energy, to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pool is also used to settle intercompany balances. The weighted-average interest rate for the money pool was 3.77%, 1.72% and 1.47% at December 31, 2005, 2004 and 2003, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded insignificant interest expense related to the money pool for all the years presented.

Strategic Resource Solutions Corp. and its subsidiary, which were wholly owned until 2004, managed subcontracts for PEC. Amounts for 2004 and 2003 were not significant.

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

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

PEC and its wholly owned subsidiaries and PEF have entered into the Tax Agreement with the Parent (See Note 14).

20. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

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

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

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

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

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

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

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

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

21. OTHER INCOME AND OTHER EXPENSE

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

Progress Energy

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

PEC

(in millions)	**2005**	2004	2003
Other income			
Nonregulated energy and delivery services income	**$ 12**	$ 11	$ 12
DIG Issue C20 amortization (Note 18A)	**7**	9	2
Income from equity investments	**1**	3	–
AFUDC equity	**3**	4	2
Other	**10**	13	2
Total other income	**33**	40	18
Other expense			
Nonregulated energy and delivery services expenses	**$ 9**	$ 9	$ 9
Donations	**8**	7	6
Losses from equity investments	**–**	3	16
FERC audit settlement	**4**	–	–
Indemnification liability (Note 22B)	**16**	–	–
Other	**10**	22	6
Total other expense	**47**	41	37
Other, net – PEC	**$ (14)**	$ (1)	$ (19)

PEF

(in millions)	**2005**	2004	2003
Other income			
Nonregulated energy and delivery services income	**$ 20**	$ 17	$ 15
Investment gains	**2**	1	2
AFUDC equity	**13**	7	12
Total other income	**35**	25	29
Other expense			
Nonregulated energy and delivery services expenses	**14**	12	11
Donations	**10**	9	9
FERC audit settlement	**3**	–	–
Other	**1**	1	2
Total other expense	**28**	22	22
Other, net – PEF	**$ 7**	$ 3	$ 7

22. ENVIRONMENTAL MATTERS

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

A. Hazardous and Solid Waste Management

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

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

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

Progress Energy

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

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

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

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

PEC

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

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

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

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

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

PEF

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

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

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

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

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

B. Air Quality

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

NEW SOURCE REVIEW (NSR)

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

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

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

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

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

CLEAN SMOKESTACKS ACT

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

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

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

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

CLEAN AIR INTERSTATE RULE (CAIR) AND MERCURY RULE

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

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

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

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

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

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

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

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

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

CLEAN AIR VISIBILITY RULE

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

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

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

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

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

C. Water Quality

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

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

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

D. Other Environmental Matters

GLOBAL CLIMATE CHANGE

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

In a decision issued July 15, 2005, a three-judge panel of the U.S. Court of Appeals for the District of Columbia Circuit denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions under the Clean Air Act. In a 2-1 decision, the court held that the EPA administrator properly exercised his discretion in denying the request for regulation. Officials from five states and the District of Columbia asked the full U.S. Court of Appeals for the D.C. Circuit to review the decision made by the three-judge panel. On December 2, 2005, the U.S. Court of Appeals denied the request for rehearing. On March 2, 2006, the petitioners filed a petition for writ of certiorari with the U.S. Supreme Court, seeking a review of the U.S. Court of Appeals decision. The outcome of this matter cannot be predicted.

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

23. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

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

Progress Energy

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

PEC

(in millions)	2006	2007	2008	2009	2010	Thereafter
Fuel	$ 881	$ 849	$ 443	$ 304	$ 151	$ 593
Purchased power	124	122	85	86	43	508
Other Purchase Obligations	14	21	20	–	–	–
Total	$ 1,019	$ 992	$ 548	$ 390	$ 194	$ 1,101

PEF

(in millions)	2006	2007	2008	2009	2010	Thereafter
Fuel	$ 545	$ 544	$ 343	$ 265	$ 104	$ 572
Purchased power	343	355	363	328	321	3,800
Construction obligations	74	28	–	–	–	–
Other purchase obligations	34	36	32	43	19	74
Total	$ 996	$ 963	$ 738	$ 636	$ 444	$ 4,446

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $3.070 billion, $2.033 billion and $1.645 billion for 2005, 2004 and 2003, respectively. PEC's total payments under these commitments for its generating plants were $964 million, $477 million and $562 million in 2005, 2004 and 2003, respectively. PEF's payments totaled $505 million, $375 million and $209 million in 2005, 2004 and 2003, respectively.

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

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

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

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $44 million, $42 million and $37 million in 2005, 2004 and 2003, respectively.

PEC has various pay-for-performance contracts with QFs for approximately 354 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $112 million in 2005, $90 million in 2004 and $113 million in 2003.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2015. Total purchases, for both energy and capacity, under these agreements amounted to $175 million, $128 million and $126 million for 2005, 2004 and 2003, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $64 million annually through 2009, $54 million for 2010 and $38 million annually thereafter through 2015.

PEF has ongoing purchased power contracts with certain QFs for 812 MW of capacity with expiration dates ranging from 2006 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the qualifying facilities meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the generating capacity of each of the facilities. All commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $262 million, $247 million and $244 million for 2005, 2004 and 2003, respectively. At December 31, 2005, minimum expected future capacity payments under these contracts were $279 million, $289 million, $297 million, $262 million and $267 million for 2006 through 2010, respectively, and $3.6 billion thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost recovery clause.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007, to April 30, 2027. The total cost to PEF associated with the agreements is approximately $4.0 billion. The transactions are subject to several conditions precedent, some of which have been satisfied, which include obtaining the FPSC's approval of the agreements, the completion and commencement of operation of the necessary related expansions to SNG's and FGT's respective natural gas pipeline systems, and other standard closing conditions. Due to the conditions in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

In January 2006, PEF entered into a conditional contract with Gulfstream Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008 through December 31, 2031. The total cost to PEF associated with this agreement is approximately $1.0 billion. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions.

Due to the timing of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $91 million, $108 million and $158 million for 2005, 2004 and 2003, respectively. At December 31, 2005, PEC has no construction obligations. Total purchases by PEC under various combustion turbine construction obligations were $5 million and $21 million for 2004 and 2003, respectively. PEC did not have any purchases related to construction obligations in 2005. PEF has purchase obligations related to various plant capital projects at the Hines Energy Complex. Total payments under PEF's contracts were $91 million, $102 million and $137 million for 2005, 2004 and 2003, respectively. PEF's future obligations under these contracts are $74 million for 2006 and $28 million for 2007.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $97 million, $58 million and $31 million for 2005, 2004 and 2003, respectively.

On December 31, 2002, PEC and PVI entered into a contractual commitment to purchase at least $11 million and $4 million, respectively, of capital parts by December 31, 2010. During 2005, 2004 and 2003, no capital parts have been purchased under this contract.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $13 million for 2005, $17 million for 2004 and $3 million for 2003. Future purchase obligations are $7 million for 2006.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $8 million, $11 million and $3 million for 2005, 2004 and 2003, respectively. Future obligations under these contracts are $14 million, $11 million, $16 million, $14 million and $19 million for 2006 through 2010, respectively, with approximately $74 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $34 million for 2005. Future obligations under these contracts are $20 million and $25 million in 2006 and 2007, respectively, and $6 million in 2008 and 2009.

PVI has purchase obligations with two counterparties for pipeline capacity through 2018 and 2028. Payments under these agreements were $15 million, $13 million and $6 million for 2005, 2004 and 2003, respectively. Future obligations under these contracts are approximately $16 million for 2006 through 2010 and approximately $117 million payable thereafter.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $48 million, $57 million and $54 million for 2005, 2004 and 2003, respectively. Our purchased power expense under agreements classified as operating leases were approximately $14 million in 2005, $25 million in 2004 and $5 million in 2003.

PEC's rent expense under operating leases totaled $24 million for 2005 and $20 million for 2004 and 2003. These amounts include rent expense allocated from PESC of $7 million for 2005 and $10 million for 2004 and 2003.

Purchased power expense under agreements classified as operating leases were approximately $11 million during 2005, $25 million during 2004 and $5 million during 2003.

PEF's rent expense under operating leases totaled $11 million, $14 million and $17 million during 2005, 2004 and 2003, respectively. These amounts include rent expense allocated from PESC to PEF of $7 million for 2005 and $10 million for 2004 and 2003. Purchased power expense under agreements classified as operating leases was approximately $3 million during 2005.

Assets recorded under capital leases at December 31 consisted of:

	Progress Energy		PEC	
(in millions)	**2005**	2004	**2005**	2004
Buildings	**$ 30**	$ 30	$ 30	$ 30
Equipment and other	**27**	2	–	–
Less: Accumulated amortization	**(12)**	(11)	(12)	(11)
Total	**$ 45**	$ 21	$ 18	$ 19

At December 31, 2005, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

	Progress Energy		PEC		PEF	
(in millions)	Capital	Operating	Capital	Operating	Capital	Operating
2006	$ 4	$ 76	$ 2	$ 36	$ –	$ 25
2007	4	88	2	31	–	45
2008	4	88	3	31	–	48
2009	4	85	2	30	–	47
2010	4	71	3	18	–	47
Thereafter	21	298	14	158	–	102
	41	$ 706	26	$ 304	–	$ 314
Less amount representing imputed interest	(12)		(7)		–	
Present value of net minimum lease payments under capital leases	$ 29		$ 19		$ –	

In 2003, we entered into a new operating lease for a building, for which minimum annual rental payments are included in the table above. The lease terms provide for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2005, PEF entered into an agreement for a new capital lease beginning in 2007 for a building that is currently under construction. The lease calls for annual payments of approximately $6 million from 2007 through 2026 for a total of approximately $110 million. The lease term provides for no payments during the last 20 years of the lease.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases for 2006 through 2010 are approximately $40 million, $24 million, $17 million, $13 million and $4 million, respectively, with $24 million receivable thereafter. Rents received under these operating leases totaled $66 million, $60 million and $45 million for 2005, 2004 and 2003, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals under noncancelable leases are $10 million for 2006 and none thereafter. Rents received are contingent upon usage and totaled $31 million, $32 million and $31 million for 2005, 2004 and 2003, respectively.

PEF's rents received are based on a fixed minimum rental where price varies by type of equipment and totaled $63 million for 2005 and 2004 and $56 million for 2003. Minimum rentals receivable (excluding streetlights) under noncancelable leases for 2006 is $5 million and none thereafter. Streetlight rentals were $42 million, $40 million and $38 million for 2005, 2004 and 2003, respectively. Future streetlight rentals would approximate 2005 revenues.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN No. 45). These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes (See Note 19). Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit, surety bonds and guarantees in support of nuclear decommissioning. At December 31, 2005, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Balance Sheets.

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

In addition, the Parent has issued $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 24).

D. Other Commitments and Contingencies

1. Spent Nuclear Fuel Matters

Pursuant to the Nuclear Waste Policy Act of 1982, the predecessors to the Utilities entered into contracts with the DOE under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Our damages due to the DOE's breach will be significant, but have yet to be determined. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

The DOE and the Utilities have agreed to a stay of the lawsuit, including discovery. The parties agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been or are expected to be presented in the trials or appeals that are currently scheduled to occur during 2006. Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The EPA has not scheduled a date for issuance of revised proposed standards. The DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and has not provided a new target date for submission of the license application. Congress approved $450 million for fiscal year 2006 for the Yucca Mountain project, approximately $201 million less than requested by the DOE. The DOE has acknowledged that a working repository will not be operational until sometime after 2010, but the DOE has not identified a new target date. The Utilities cannot predict the outcome of this matter.

On February 27, 2004, PEC requested to have its license for the Independent Spent Fuel Storage Installation at Robinson extended by 20 years with an exemption request for an additional 20-year extension. Its current license expires in August 2006 and on March 30, 2005, the NRC issued a 40-year license renewal.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at Robinson and Brunswick, PEC's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEC's system through the expiration of the operating licenses for all of PEC's nuclear generating units.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at PEF's nuclear unit, CR3, PEF's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEF's system through the expiration of the operating license for CR3.

2. Synthetic Fuel Matters

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that own facilities that produce coal-based solid synthetic fuel as defined under Section 29 of the Code (Section 29). The production and sale of the synthetic fuel from these facilities qualify for tax credits under Section 29/45K if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the coal used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuel facilities entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuel produced and sold by these plants.

On August 8, 2005, the Energy Policy Act of 2005 (EPACT) was signed into law. This new federal law contains key provisions affecting the electric power industry, including the redesignation of the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K). The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are currently carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section

45K general business credit was effective on January 1, 2006, and removes the regular federal income tax liability limit on synthetic fuel production and subjects the credits to a 20-year carry forward period. This provision would allow us to produce synthetic fuel to a higher level than we have historically produced should we choose to do so.

Total Section 29 credits generated through December 31, 2005 (including those generated by Florida Progress prior to our acquisition), are approximately $1.7 billion, of which $819 million has been used to offset regular federal income tax liability and $922 million is being carried forward as deferred alternative minimum tax credits. The current synthetic fuel tax credit program expires at the end of 2007.

IRS PROCEEDINGS

In July 2004, we were notified that the IRS field auditors anticipated taking an adverse position regarding the placed-in-service date of the Earthco facilities. On October 29, 2004, we received the IRS field auditors' preliminary report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and proposing that the tax credits generated by those facilities be disallowed.

During October 2005, we and the IRS field auditors filed briefs with the National Office for the purpose of receiving technical advice on whether our Earthco facilities were placed in service prior to July 1, 1998, in order to determine if our synthetic fuel tax credits are allowable under Section 29 of the Internal Revenue Code. During February 2006, the IRS field auditors verbally informed us that the IRS National Office concluded that our four Earthco synthetic fuel facilities met the placed-in-service requirement. The IRS field auditors also indicated that, once they receive written confirmation of the National Office's conclusion, the IRS field auditors will close their audit without any disallowance of tax credits. On February 28, 2006, we received our copy of the National Office Technical Advice Memorandum that concludes that the Earthco facilities met the placed-in-service requirement.

PERMANENT SUBCOMMITTEE

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29. The investigation is examining the utilization of the credits, the nature of the technologies and fuels created, the use of the synthetic fuel and other aspects of Section 29 and is not specific to our synthetic fuel operations. Progress Energy provided information in connection with this investigation. We cannot predict the outcome of this matter.

IMPACT OF CRUDE OIL PRICES

Although the Section 29/45K tax credit program is expected to continue through 2007, recent market conditions, world events and catastrophic weather events have increased the volatility and level of oil prices that could limit the amount of those credits or eliminate them entirely for the years following 2005. This possibility is due to a provision of Section 29 that provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold price (the Threshold Price), the amount of Section 29/45K tax credits is reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. Synthetic fuel is not economical to produce absent the associated tax credits.

If the Annual Average Price falls between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits are reduced will depend on where the Annual Average Price falls in that continuum. For example, for 2004, the Threshold Price was $51.35 per barrel and the Phase-out Price was $64.47 per barrel. If the Annual Average Price had been $57.91 per barrel, there would have been a 50 percent reduction in the amount of Section 29 tax credits for that year.

The secretary of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency (EIA). Because the EIA publishes its information on a three-month lag, the secretary of the Treasury finalizes the calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2005 is expected to be published in early April 2006.

We estimate that the 2005 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $65 per barrel, based on an estimated 2005 inflation adjustment. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding monthly New York Mercantile Exchange (NYMEX) settlement price for light sweet crude oil. Through December 31, 2005, the average NYMEX contract settlement price for light sweet crude oil was $55 per barrel. Assuming that the $5 average differential between the Domestic Crude Oil First Purchases Price published by the EIA and the NYMEX settlement price continued through December 31, 2005, we do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits in 2005.

We estimate that the 2006 Threshold Price will be approximately $52 per barrel and the Phase-out Price will be approximately $66 per barrel, based on estimated inflation adjustments for 2005 and 2006. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $5 lower than the corresponding monthly NYMEX settlement price for light sweet crude oil. As of January 31, 2006, the average NYMEX futures price for light sweet crude oil for calendar year 2006 was $69 per barrel. Based upon the estimated 2006 Threshold Price and Phase-out Price, if oil prices for 2006 remained at the January 31, 2006, average futures price level of $69 per barrel for the entire year in 2006, we currently estimate that the synthetic fuel tax credit amount for 2006 would be reduced by approximately 75 percent to 85 percent. Therefore, the estimated value of 2006 tax credits of approximately $27 per ton would be reduced to approximately $4 to $7 per ton for any synthetic fuel produced in 2006.

In November 2005, the U.S. Senate passed Senate Bill 2020, The Tax Relief Act of 2005, which includes proposed modifications to the Section 29/45K synthetic fuel tax credit program. This legislation would provide synthetic fuel producers with additional certainty around future synthetic fuel production decisions. The proposed modifications include amendments of the phase-out calculation and the annual inflation adjustment for the value of the synthetic fuel tax credits. Under Senate Bill 2020, the Annual Average Price, Threshold Price and the Phase-out Price for 2006 and 2007 would be based on the calculated amounts for the previous calendar year. In addition, the annual inflation adjustment for the synthetic fuel tax credits for 2005, 2006 and 2007 would be eliminated. The U.S. House version of the Tax Reconciliation bill does not include these same provisions. The differences in the Senate and House versions of the bill will be reconciled in conference. We cannot predict with any certainty the likelihood of this legislation passing.

As noted above, we do not currently believe that the 2005 Annual Average Price will cause a phase-out of the synthetic fuel tax credits related to synthetic fuel production in 2005. Therefore, if the provisions of Senate Bill 2020 regarding changes to the Section 29/45K synthetic fuel tax credit program were enacted into law, there would be no phase-out of these tax credits in calendar year 2006. However, we cannot predict with any certainty the price of oil for 2006 or 2007 and, therefore, we cannot predict what impact, if any, this proposed legislation would have on the value of tax credits in 2007.

Our future synthetic fuel production levels for 2006 and 2007 remain uncertain because we cannot predict with any certainty the Annual Average Price of oil for 2006 or 2007 or the likelihood of legislation modifying the phase-out calculation being enacted into law. If oil prices for 2006 remained at the January 31, 2006, average futures price level of $69 per barrel for the entire year in 2006, it is unlikely that we would produce significant amounts of synthetic fuel in 2006 and could potentially forfeit credits associated with any 2006 synthetic fuel production. This could have a material adverse impact on our results of operations. We will continue to monitor the level of oil prices and retain the ability to adjust production based on future oil price levels.

Due to the significant uncertainty surrounding our synthetic fuel production in 2006 and 2007 based on the current level of oil prices, we evaluated our synthetic fuel and other related operating long-lived assets for impairment during the third quarter and fourth quarter of 2005. We determined that no impairment of these assets was required. However, an increase in oil prices or a decrease in future synthetic fuel production and cash flows could require additional impairment evaluations in the future, which could result in a future impairment of these assets, which have total carrying values as of December 31, 2005, of approximately $111 million. The majority of these assets will be fully depreciated by the end of 2007, the scheduled end of the synthetic fuel tax credit program. The outcome of this matter cannot be determined.

SALE OF PARTNERSHIP INTEREST

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona, one of our synthetic fuel facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gains from the sales will be recognized on a cost recovery basis as the facility produces and sells synthetic fuel and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectability is reasonably assured. Gain recognition is dependent on the synthetic fuel production qualifying for Section 29 tax credits and the value of such tax credits as discussed above. Until the gain recognition criteria are met, gains from selling interests in Colona will be deferred. It is possible that gains will be deferred in the first, second and/or third quarters of each year until there is persuasive evidence that no tax credit phase-out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters in a calendar year. In the event that the synthetic fuel tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuel tax credits, the amount of proceeds realized from the sale could be significantly impacted. We recognized a pre-tax gain on monetization of $30 million during 2005 based on the remote possibility of any phase-out of the synthetic fuel tax credits in 2005. A portion of this gain had been deferred through the third quarter of 2005.

CONTINGENT ROYALTY PAYMENTS

We have certain future commitments related to four synthetic fuel facilities purchased that provide for contingent payments (royalties). The related agreements and their amendments require the payment of minimum annual royalties of approximately $7 million for each plant through 2007. We recorded a liability (included in other liabilities and deferred credits on the Consolidated Balance Sheets) and a deferred asset (included in other assets and deferred debits in the Consolidated Balance Sheets), each of approximately $50 million and $73 million at December 31, 2005 and 2004, respectively, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2005 and 2004, the portions of the asset and liability recorded that were classified as current were approximately $26 million. The deferred asset will be amortized to expense each year as synthetic fuel sales are made. The maximum amounts payable under these agreements remain unchanged. Future expected annual minimum royalty payments are approximately $26 million for 2006 and 2007. We have exercised our right under the related agreements to escrow those payments if certain conditions in the agreements were met, as more fully described below.

On May 15, 2005, the original owners of the Earthco synthetic fuel facilities filed suit in New York state court alleging breach of contract against the Progress Fuels subsidiaries that purchased the Earthco facilities (Progress Fuels Subsidiaries). The plaintiffs also named us as a defendant. The plaintiffs allege that periodic payments due to them under the sales arrangement with the Progress Fuels Subsidiaries are being improperly withheld and escrowed. The Progress Fuels Subsidiaries believe that the parties' agreements allow for the payments to be escrowed in the event of an audit, investigation or other proceeding under which the IRS can disallow the tax credits associated with the Earthco facilities. They also believe that the agreements allow for the use of such escrowed amounts to satisfy any potential disallowance of tax credits that arises out of such an event. Currently, the escrowed amount in question is $97 million, which reflects periodic payments that would have been paid to the plaintiffs beginning April 30, 2003, through January 31, 2006. This amount will increase as future periodic payments are made to the escrow, which would otherwise have been payable to the plaintiffs. Plaintiffs filed a partial summary judgment motion in December 2005 seeking payment of the escrowed money. The Progress Fuels Subsidiaries oppose the motion and will file opposition papers, which are not yet due. The parties are now engaged in discovery.

In addition, a number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global LLC (Global), Earthco, certain affiliates of Earthco (collectively the Earthco Sellers), EFC Synfuel LLC (which is owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC, Solid Fuel LLC, Ceredo Synfuel LLC, Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted that pursuant to the Asset Purchase Agreement it is entitled to an interest in two synthetic fuel facilities currently owned by the Progress Affiliates, and an option to purchase additional interests in the two synthetic fuel facilities.

The first suit, U.S. Global LLC v. Progress Energy, Inc. et al., was filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case). The Florida Global Case asserts claims for breach of the Asset Purchase Agreement and other contract and tort claims related to the Progress Affiliates' alleged interference with Global's rights under the Asset Purchase Agreement. The Florida Global Case requests an unspecified amount of compensatory damages, as well as declaratory relief. Following briefing and argument on a number of dispositive motions on successive versions of Global's complaint, on August 16, 2004, the Progress Affiliates answered the Fourth Amended Complaint by generally denying all of Global's substantive allegations and asserting numerous affirmative defenses. The parties are currently engaged in discovery in the Florida Global Case.

The second suit, Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC, was filed by the Progress Affiliates in the Superior Court for Wake County, N.C., seeking declaratory relief consistent with our interpretation of the Asset Purchase Agreement (the North Carolina Global Case). Global was served with the North Carolina Global Case on April 17, 2003.

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss and entered an order staying the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the Superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal.

The Progress Affiliates believe that the parties' agreements allow for the payments due to Global to be escrowed in the event of an audit, investigation or other proceeding under which the IRS can disallow the tax credits and also allow for the use of such escrowed amounts to satisfy any potential disallowance of tax credits that arises out of such an event. Currently, the escrowed amount in question is $37 million, which reflects periodic payments that would have been paid to the plaintiffs beginning April 30, 2003, through January 31, 2006. This amount will increase as future periodic payments are made to the escrow that would otherwise have been payable to the plaintiffs.

We cannot predict the outcome of these matters, but will vigorously defend against the allegations.

3. Franchise Matters

PEF has largely resolved its outstanding franchise matters. In August 2005, the cities of Edgewood, Fla. (1,400 customers), and Maitland, Fla. (7,000 customers), approved new 30-year electric utility franchise agreements with PEF. In November 2005, the 2,500 customer town of Belleair, Fla., voted to reject a referendum to municipalize, but has not yet signed a new utility franchise agreement with PEF. As previously noted, in accordance with the terms of an arbitration panel's award issued in May 2003 and after satisfying regulatory and operational requirements, Winter Park acquired from PEF the electric distribution system that serves Winter Park (14,000 customers) and PEF transferred the distribution system to Winter Park on June 1, 2005. In addition, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option (See Note 7C).

4. Other Litigation Matters

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

24. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the condensed consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The yearly interest expense is $21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2005, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN No. 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements and resulted in recording an additional equity investment in the Trust of approximately $9 million, an increase in outstanding debt of approximately $8 million and a gain of approximately $1 million relating to the cumulative effect of a change in accounting principle. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries.

Condensed Consolidating Statement of Income
Year Ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$ 3,955	$ 3,990	$ 7,945
Diversified business	–	1,496	667	2,163
Total operating revenues	–	5,451	4,657	10,108
Operating expenses				
Utility				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	334	588	922
Taxes other than on income	4	279	177	460
Other	–	(26)	(11)	(37)
Diversified business				
Cost of sales	–	1,338	737	2,075
Depreciation and amortization	–	79	73	152
Other	–	41	33	74
Total operating expenses	16	4,914	3,893	8,823
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Other income (expense), net	66	(4)	(51)	11
Interest charges, net	300	178	162	640
Income (loss) from continuing operations before income tax and minority interest	634	355	(333)	656
Income tax (benefit) expense	(63)	(40)	58	(45)
Minority interest in subsidiaries' loss, net of tax	–	(26)	–	(26)
Income (loss) from continuing operations	697	421	(391)	727
Discontinued operations, net of tax	–	(47)	16	(31)
Cumulative effect of changes in accounting principles, net of tax	–	–	1	1
Net income (loss)	$ 697	$ 374	$ (374)	$ 697

Condensed Consolidating Statement of Income
Year Ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$ 3,525	$ 3,628	$ 7,153
Diversified business	–	1,125	247	1,372
Total operating revenues	–	4,650	3,875	8,525
Operating expenses				
Utility				
Fuel used in electric generation	–	1,175	836	2,011
Purchased power	–	567	301	868
Operation and maintenance	10	630	835	1,475
Depreciation and amortization	–	281	597	878
Taxes other than on income	(2)	254	173	425
Other	–	(2)	(11)	(13)
Diversified business				
Cost of sales	–	981	198	1,179
Depreciation and amortization	–	78	79	157
Other	–	17	84	101
Total operating expenses	8	3,981	3,092	7,081
Equity in earnings of consolidated subsidiaries	940	–	(940)	–
Other income (expense), net	65	(4)	(59)	2
Interest charges, net	295	162	171	628
Income (loss) from continuing operations before income tax and minority interest	702	503	(387)	818
Income tax (benefit) expense	(57)	61	102	106
Minority interest in subsidiaries' loss, net of tax	–	(17)	–	(17)
Income (loss) from continuing operations	759	459	(489)	729
Discontinued operations, net of tax	–	15	15	30
Net income (loss)	$ 759	$ 474	$ (474)	$ 759

Condensed Consolidating Statement of Income
Year Ended December 31, 2003

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$ 3,152	$ 3,589	$ 6,741
Diversified business	–	830	228	1,058
Total operating revenues	–	3,982	3,817	7,799
Operating expenses				
Utility				
Fuel used in electric generation	–	870	825	1,695
Purchased power	–	566	296	862
Operation and maintenance	19	640	762	1,421
Depreciation and amortization	–	307	576	883
Taxes other than on income	2	241	162	405
Other	–	–	(8)	(8)
Diversified business				
Cost of sales	–	736	193	929
Depreciation and amortization	–	62	64	126
Other	–	80	62	142
Total operating expenses	21	3,502	2,932	6,455
Equity in earnings of consolidated subsidiaries	1,039	–	(1,039)	–
Other income (expense), net	47	(8)	(76)	(37)
Interest charges, net	319	142	146	607
Income (loss) from continuing operations before income tax and minority interest	746	330	(376)	700
Income tax (benefit) expense	(36)	(112)	35	(113)
Minority interest in subsidiaries' income, net of tax	–	2	–	2
Income (loss) from continuing operations	782	440	(411)	811
Discontinued operations, net of tax	–	7	(12)	(5)
Cumulative effect of changes in accounting principles, net of tax	–	–	(24)	(24)
Net income (loss)	$ 782	$ 447	$ (447)	$ 782

Condensed Consolidating Balance Sheet
December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$ –	$ 5,821	$ 8,621	$ 14,442
Current assets				
Cash and cash equivalents	239	241	126	606
Short-term investments	–	–	191	191
Receivables from affiliated companies	713	–	(713)	–
Deferred fuel cost	–	341	261	602
Assets of discontinued operations	–	107	2	109
Other current assets	22	1,069	1,139	2,230
Total current assets	974	1,758	1,006	3,738
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,594	–	(11,594)	–
Goodwill	–	2	3,717	3,719
Other assets and deferred debits	13	2,174	2,937	5,124
Total deferred debits and other assets	11,607	2,176	(4,940)	8,843
Total assets	$ 12,581	$ 9,755	$ 4,687	$ 27,023
Capitalization				
Common stock equity	$ 8,038	$ 3,039	$ (3,039)	$ 8,038
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	38	5	43
Long-term debt, affiliate	–	440	(170)	270
Long-term debt, net	3,873	2,636	3,667	10,176
Total capitalization	11,911	6,187	522	18,620
Current liabilities				
Current portion of long-term debt	404	109	–	513
Notes payable to affiliated companies	–	315	(315)	–
Short-term obligations	–	102	73	175
Liabilities of discontinued operations	–	40	–	40
Other current liabilities	245	855	1,017	2,117
Total current liabilities	649	1,421	775	2,845
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	60	218	278
Regulatory liabilities	–	1,189	1,338	2,527
Accrued pension and other benefits	12	307	551	870
Other liabilities and deferred credits	9	591	1,283	1,883
Total deferred credits and other liabilities	21	2,147	3,390	5,558
Total capitalization and liabilities	$ 12,581	$ 9,755	$ 4,687	$ 27,023

Condensed Consolidating Balance Sheet
December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	**$** –	$ 5,882	$ 8,481	$ 14,363
Current assets				
Cash and cash equivalents	5	24	27	56
Short-term investments	–	–	82	82
Receivables from affiliated companies	1,415	5	(1,420)	–
Deferred fuel cost	–	89	140	229
Assets of discontinued operations	–	696	(11)	685
Other current assets	23	920	1,037	1,980
Total current assets	1,443	1,734	(145)	3,032
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,061	–	(11,061)	–
Goodwill	–	2	3,717	3,719
Other assets and deferred debits	16	2,068	2,846	4,930
Total deferred debits and other assets	11,077	2,070	(4,498)	8,649
Total assets	$ 12,520	$ 9,686	$ 3,838	$ 26,044
Capitalization				
Common stock equity	$ 7,633	$ 2,681	$ (2,681)	$ 7,633
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	32	4	36
Long-term debt, affiliate	–	809	(539)	270
Long-term debt, net	4,449	2,052	2,750	9,251
Total capitalization	12,082	5,608	(407)	17,283
Current liabilities				
Current portion of long-term debt	–	49	300	349
Notes payable to affiliated companies	–	431	(431)	–
Short-term obligations	170	293	221	684
Liabilities of discontinued operations	–	186	–	186
Other current liabilities	245	931	688	1,864
Total current liabilities	415	1,890	778	3,083
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	64	584	648
Regulatory liabilities	–	1,362	1,292	2,654
Accrued pension and other benefits	10	248	375	633
Other liabilities and deferred credits	13	514	1,216	1,743
Total deferred credits and other liabilities	23	2,188	3,467	5,678
Total capitalization and liabilities	$ 12,520	$ 9,686	$ 3,838	$ 26,044

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 257	$ 515	$ 702	$ 1,474
Investing activities				
Gross utility property additions	–	(496)	(584)	(1,080)
Diversified business property additions	–	(190)	(16)	(206)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	702	5	(707)	–
Contributions to consolidated subsidiaries	(13)	–	13	–
Acquisition of intangibles	–	–	(3)	(3)
Other investing activities	1	(26)	(12)	(37)
Net cash provided (used) by investing activities	690	(292)	(1,515)	(1,117)
Financing activities				
Issuance of common stock	208	–	–	208
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Net decrease in short-term indebtedness	(170)	(191)	(148)	(509)
Retirement of long-term debt	(160)	(473)	69	(564)
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Changes in advances from affiliates	–	(101)	101	–
Contributions from parent	–	11	(11)	–
Other financing activities	(9)	40	1	32
Net cash (used) provided by financing activities	(713)	28	912	227
Cash used by discontinued operations				
Operating activities	–	(13)	–	(13)
Investing activities	–	(21)	–	(21)
Financing activities	–	–	–	–
Net increase in cash and cash equivalents	234	217	99	550
Cash and cash equivalents at beginning of year	5	24	27	56
Cash and cash equivalents at end of year	$ 239	$ 241	$ 126	$ 606

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 653	$ 571	$ 341	$ 1,565
Investing activities				
Gross utility property additions	–	(482)	(516)	(998)
Diversified business property additions	–	(150)	(19)	(169)
Nuclear fuel additions	–	–	(101)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	343	30	373
Purchases of available-for-sale securities and other investments	–	(569)	(2,565)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	–	569	2,679	3,248
Changes in advances to affiliates	27	(5)	(22)	–
Contributions to consolidated subsidiaries	(15)	–	15	–
Acquisition of intangibles	–	–	(1)	(1)
Other investing activities	–	(23)	(6)	(29)
Net cash provided (used) by investing activities	12	(317)	(506)	(811)
Financing activities				
Issuance of common stock	73	–	–	73
Proceeds from issuance of long-term debt, net	365	56	–	421
Net increase in short-term indebtedness	170	293	217	680
Retirement of long-term debt	(705)	(68)	(580)	(1,353)
Dividends paid on common stock	(558)	–	–	(558)
Dividends paid to parent	–	(340)	340	–
Changes in advances from affiliates	–	(209)	209	–
Contributions from parent	–	12	(12)	–
Other financing activities	(5)	13	(2)	6
Net cash (used) provided by financing activities	(660)	(243)	172	(731)
Cash provided (used) by discontinued operations				
Operating activities	–	44	–	44
Investing activities	–	(46)	–	(46)
Financing activities	–	–	–	–
Net increase in cash and cash equivalents	5	9	7	21
Cash and cash equivalents at beginning of year	–	15	20	35
Cash and cash equivalents at end of year	$ 5	$ 24	$ 27	$ 56

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2003

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 524	$ 517	$ 547	$ 1,588
Investing activities				
Gross utility property additions	–	(526)	(446)	(972)
Diversified business property additions	–	(302)	(146)	(448)
Nuclear fuel additions	–	(51)	(66)	(117)
Proceeds from sales of discontinued operations and other assets, net of cash divested	451	100	28	579
Purchases of available-for-sale securities and other investments	–	(441)	(3,351)	(3,792)
Proceeds from sales of available-for-sale securities and other investments	–	441	3,088	3,529
Changes in advances to affiliates	(327)	(16)	343	–
Contributions to consolidated subsidiaries	(411)	–	411	–
Acquisition of intangibles	–	–	(200)	(200)
Other investing activities	(1)	(15)	21	5
Net cash used in investing activities	(288)	(810)	(318)	(1,416)
Financing activities				
Issuance of common stock	304	–	–	304
Proceeds from issuance of long-term debt, net	–	935	604	1,539
Net decrease in short-term indebtedness	–	(258)	(438)	(696)
Retirement of long-term debt	–	(534)	(276)	(810)
Dividends paid on common stock	(541)	–	–	(541)
Dividends paid to parent	–	(301)	301	–
Changes in advances from affiliates	–	274	(274)	–
Contributions from parent	–	168	(168)	–
Other financing activities	–	–	16	16
Net cash (used) provided by financing activities	(237)	284	(235)	(188)
Cash provided (used) by discontinued operations				
Operating activities	–	123	–	123
Investing activities	–	(126)	–	(126)
Financing activities	–	–	–	–
Net decrease in cash and cash equivalents	(1)	(12)	(6)	(19)
Cash and cash equivalents at beginning of year	1	27	26	54
Cash and cash equivalents at end of year	$ –	$ 15	$ 20	$ 35

25. SUBSEQUENT EVENT

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

The sale is expected to close by mid-2006, and is subject to various closing conditions customary to such transactions. We expect to report PT LLC as a discontinued operation in the first quarter of 2006. The carrying amounts for the assets and liabilities of the discontinued operations disposal group included in the Consolidated Balance Sheets as of December 31 were as follows:

(in millions)	**2005**	2004
Total current assets	**$ 12**	$ 16
Total property, plant and equipment, net	**79**	75
Total other assets	**23**	39
Total current liabilities	**8**	15
Total long-term liabilities	**35**	34
Minority interest	**24**	21
Total capitalization	**47**	60

26. QUARTERLY FINANCIAL DATA (UNAUDITED)

Results of operations for an interim period may not give a true indication of results for the year. In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First (a)(b)	Second (a)(b)	Third (a)(b)	Fourth (a)(b)
2005				
Operating revenues	**$ 2,168**	**$ 2,295**	**$ 3,067**	**$ 2,578**
Operating income	**252**	**143**	**558**	**332**
Income from continuing operations before cumulative effect of changes in accounting principles	**104**	**7**	**459**	**157**
Net income	**93**	**(1)**	**450**	**155**
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	**0.43**	**0.03**	**1.86**	**0.63**
Net income	**0.38**	**(0.01)**	**1.82**	**0.62**
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	**0.43**	**0.03**	**1.85**	**0.63**
Net income	**0.38**	**(0.01)**	**1.81**	**0.62**
Dividends declared per common share	**0.590**	**0.590**	**0.590**	**0.605**
Market price per share – High	**45.33**	**45.83**	**46.00**	**45.50**
– Low	**40.63**	**40.61**	**41.90**	**40.19**
2004				
Operating revenues	$ 1,987	$ 2,085	$ 2,445	$ 2,008
Operating income	283	288	567	306
Income from continuing operations before cumulative effect of changes in accounting principles	102	145	287	195
Net income	108	154	303	194
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.42	0.59	1.18	0.81
Net income	0.45	0.63	1.25	0.80
Diluted earnings per common share				
Income from continuing operations before cumulative effect of changes in accounting principles	0.42	0.59	1.18	0.81
Net income	0.45	0.63	1.24	0.80
Dividends declared per common share	0.575	0.575	0.575	0.590
Market price per share – High	47.95	47.50	44.32	46.10
– Low	43.02	40.09	40.76	40.47

(a) Operating results have been restated for discontinued operations.
(b) Certain amounts have been reclassified to conform with current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. First quarter 2005 includes $31 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative at PEF (See Note 17). Second quarter 2005 includes a $141 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 17). The 2004 amounts were restated for discontinued operations (See Notes 3A and 3B). Fourth quarter 2004 includes a $31 million after-tax gain on sale of natural gas assets (See Note 3E) and $90 million of Section 29 tax credits being recorded (See Note 23D). Third quarter 2004 includes reversal of $79 million of Section 29 tax credits (See Note 23D).

PEC

Summarized quarterly financial data was as follows:

(in millions)	First (a)	Second (a)	Third (a)	Fourth (a)
2005				
Operating revenues	**$ 935**	**$ 861**	**$ 1,185**	**$ 1,010**
Operating income	**221**	**140**	**343**	**227**
Net income	**116**	**67**	**184**	**126**
2004				
Operating revenues	$ 901	$ 862	$ 1,014	$ 852
Operating income	236	192	320	141
Net income	115	96	175	75

(a) Certain amounts have been reclassified to conform with current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. First quarter 2005 includes $14 million recorded for estimated severance expense for workforce restructuring (See Note 17). Second quarter 2005 includes a $29 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 17). Fourth quarter 2004 includes $99 million of Clean Smokestacks Act amortization. Fourth quarter 2003 includes impairment of investments of $21 million ($13 million after-tax) (See Note 7). Fourth quarter 2003 includes a cumulative effect for DIG Issue C20 of $38 million ($23 million after-tax) (See Note 13).

PEF

Summarized quarterly financial data was as follows:

(in millions)	First (a)	Second (a)	Third (a)	Fourth (a)
2005				
Operating revenues	**$ 848**	**$ 908**	**$ 1,227**	**$ 972**
Operating income	**89**	**51**	**247**	**112**
Net income	**44**	**10**	**151**	**55**
2004				
Operating revenues	$ 784	$ 860	$ 1,029	$ 852
Operating income	103	157	245	115
Net income	50	84	140	61

(a) Certain amounts have been reclassified to conform with current period presentation.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. First quarter 2005 includes $14 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading initiative (See Note 17). Second quarter 2005 includes a $90 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 17).

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF PROGRESS ENERGY, INC.:

We have audited the consolidated financial statements of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, management's assessment of the effectiveness of the Company's internal control over financial reporting at December 31, 2005, and the effectiveness of the Company's internal control over financial reporting at December 31, 2005, and have issued our reports thereon dated March 6, 2006 (which reports on the consolidated financial statements express an unqualified opinion and include an explanatory paragraph concerning the adoption of new accounting principles in 2005 and 2003); such consolidated financial statements and reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

PROGRESS ENERGY, INC.
Schedule II – Valuation and Qualifying Accounts
For the Years Ended
(in millions)

Description	Balance at Beginning of Period	Additions Charged to Expenses	Other Additions	Deductions (a)		Balance at End of Period
Valuation and qualifying accounts deducted in the balance sheet from the related assets:						
DECEMBER 31, 2005						
Uncollectible accounts	**$ 22**	**$ 16**	**$ –**	**$ (19)**		**$ 19**
Fossil dismantlement reserve	**144**	**1**	**–**	**–**		**145**
Nuclear refueling outage reserve	**12**	**11**	**–**	**(21)**	(b)	**2**
DECEMBER 31, 2004						
Uncollectible accounts	$ 28	$ 14	$ (4)	$ (16)		$ 22
Fossil dismantlement reserve	143	1	–	–		144
Nuclear refueling outage reserve	2	10	–	–		12
DECEMBER 31, 2003						
Uncollectible accounts	$ 17	$ 16	$ 4	$ (9)		$ 28
Fossil dismantlement reserve	142	1	–	–		143
Nuclear refueling outage reserve	10	8	–	(16)	(b)	2

(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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC.:

We have audited the consolidated financial statements of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., and its subsidiaries (PEC) at December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, and have issued our report thereon dated March 6, 2006 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2005 and 2003); such consolidated financial statements and report are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of PEC listed in Item 15. This consolidated financial statement schedule is the responsibility of PEC's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
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, 2005					
Uncollectible accounts	**$ 10**	**$ 5**	**$ –**	**$ (11)**	**$ 4**
DECEMBER 31, 2004					
Uncollectible accounts	$ 17	$ 7	$ (4)	$ (10)	$ 10
DECEMBER 31, 2003					
Uncollectible accounts	$ 12	$ 12	**$** 4	$ (11)	$ 17

(a) Deductions from provisions represent losses or expenses for which the respective provisions were created. Such deductions are reduced by recoveries of amounts previously written off.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDER OF FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.:

We have audited the financial statements of Florida Power Corporation d/b/a Progress Energy Florida, Inc., (PEF) at December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, and have issued our report thereon dated March 6,, 2006 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2005 and 2003); such financial statements and report are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of PEF listed in Item 15. This financial statement schedule is the responsibility of PEF's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
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, 2005						
Uncollectible accounts	**$ 2**	**$ 10**	**$ –**	**$ (6)**		**$ 6**
Fossil dismantlement reserve	**144**	**1**	**–**	**–**		**145**
Nuclear refueling outage reserve	**12**	**11**	**–**	**(21)**	**(b)**	**2**
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

(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

Progress Energy, Inc.

DISCLOSURE CONTROLS AND PROCEDURES

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, we carried out an evaluation, with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in the reports that we file or submit 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 our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

Management's assessment of the effectiveness of Progress Energy's internal control over financial reporting at

December 31, 2005, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein in ITEM 9A, "Controls and Procedures."

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING.

On November 14, 2005, Progress Energy announced that Geoffrey S. Chatas, Executive Vice President and Chief Financial Officer of Progress Energy and its subsidiaries, resigned as an officer of Progress Energy and its subsidiaries to pursue other interests effective the close of business on November 14, 2005. Peter M. Scott III, President and Chief Executive Officer of Progress Energy Service Company, LLC, was appointed Chief Financial Officer of Progress Energy and its subsidiaries.

Other than the above-referenced item, there has been no change in Progress Energy's internal control over financial reporting during the quarter ended December 31, 2005 that has materially affected, or is reasonably likely to materially affect its internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF PROGRESS ENERGY, INC.

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

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

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

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

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

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

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

PEC

Pursuant to the Securities Exchange Act of 1934, PEC carried out an evaluation, with the participation of its management, including PEC's Chief Executive Officer and Chief Financial Officer, of the effectiveness of PEC'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, PEC'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 PEC's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

On November 14, 2005, Progress Energy announced that Geoffrey S. Chatas, Executive Vice President and Chief Financial Officer of Progress Energy and its subsidiary, PEC, resigned as an officer of Progress Energy and PEC to pursue other interests effective the close of business on November 14, 2005. Peter M. Scott III, President and Chief Executive Officer of Progress Energy Service Company, LLC, was appointed Chief Financial Officer of Progress Energy and PEC.

Other than the above-referenced item, there has been no change in PEC's internal control over financial reporting during the quarter ended December 31, 2005 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PEF

Pursuant to the Securities Exchange Act of 1934, PEF carried out an evaluation, 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 PEF 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.

On November 14, 2005, Progress Energy announced that Geoffrey S. Chatas, Executive Vice President and Chief Financial Officer of Progress Energy and its subsidiary, PEF, resigned as an officer of Progress Energy and PEF to pursue other interests effective the close of business on November 14, 2005. Peter M. Scott III, President and Chief Executive Officer of Progress Energy Service Company, LLC, was appointed Chief Financial Officer of Progress Energy and PEF.

Other than the above-referenced item, there has been no change in PEF's internal control over financial reporting during the quarter ended December 31, 2005 that has materially affected, or is reasonably like to materially affect, PEF's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

a) Information on Progress Energy, Inc.'s directors is set forth in Progress Energy's definitive proxy statement for the 2006 Annual Meeting of Shareholders and incorporated by reference herein. Information on PEC's directors is set forth in PEC's definitive proxy statement for the 2006 Annual Meeting of Shareholders and incorporated by reference herein.

b) Information on both Progress Energy's and PEC's executive officers is set forth in PART I and incorporated by reference herein.

c) We have adopted a Code of Ethics that applies to all of our employees, including our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller (or persons performing similar functions). Our board of directors has adopted our Code of Ethics as its own standard. Board members, Progress Energy officers and Progress Energy employees certify their compliance with the Code of Ethics on an annual basis. Our Code of Ethics is posted on our Web site at www.progress-energy.com and is available in print to any shareholder upon request by writing to Progress Energy, Inc.

We intend to satisfy the disclosure requirement under Item 10 of Form 8-K relating to amendments to or waivers from any provision of the Code of Ethics applicable to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and Controller by posting such information on our Internet Web site, www.progress-energy.com.

d) The board of directors has determined that David L. Burner and Carlos A. Saladrigas are the "Audit Committee Financial Experts," as that term is defined in the rules promulgated by the Securities and Exchange Commission pursuant to the Sarbanes-Oxley Act of 2002, and have designated them as such. Both Mr. Burner and Mr. Saladrigas are "independent," as that term is defined in the general independence standards of the New York Stock Exchange listing standards.

e) The following are available on our Web site and in print at no cost:
- Audit Committee Charter
- Corporate Governance Committee Charter
- Organization and Compensation Committee Charter
- Corporate Governance Guidelines

The information called for by ITEM 10 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 11. EXECUTIVE COMPENSATION

Information on Progress Energy's executive compensation is set forth in Progress Energy's definitive proxy statement for the 2006 Annual Meeting of Shareholders and incorporated by reference herein. Information on PEC's executive compensation is set forth in PEC's definitive proxy statement for the 2006 Annual Meeting of Shareholders and incorporated by reference herein.

The information called for by ITEM 11 is omitted for PEF 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 AND RELATED STOCKHOLDER MATTERS

a) Information regarding any person Progress Energy knows to be the beneficial owner of more than five (5%) percent of any class of its voting securities is set forth in its definitive proxy statement for the 2006 Annual Meeting of Shareholders and incorporated herein by reference.

Information regarding any person PEC knows to be the beneficial owner of more than five (5%) of any class of its voting securities is set forth in its definitive proxy statement for the 2006 Annual Meeting of Shareholders and incorporated herein by reference.

b) Information on security ownership of the Progress Energy's and PEC's management is set forth respectively in Progress Energy's and PEC's definitive proxy statements for the 2006 Annual Meeting of Shareholders and incorporated by reference herein.

c) Information on the equity compensation plans of Progress Energy is set forth under the heading "Equity Compensation Plan Information" in Progress Energy's definitive proxy statement for the 2006 Annual Meeting of Shareholders and incorporated by reference herein.

The information called for by ITEM 12 is omitted for PEF 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

Information on certain relationships and related transactions is set forth respectively in Progress Energy's and PEC's definitive proxy statements for the 2006 Annual Meeting of Shareholders and incorporated by reference herein.

The information called for by ITEM 13 is omitted for PEF pursuant to Instruction I(2)(c) to Form 10-K (Omission of Information by Certain Wholly Owned Subsidiaries).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The Audit and Corporate Performance Committee of Progress Energy's board of directors ("Audit Committee") has actively monitored all services provided by its independent registered public accounting firm, Deloitte & Touche LLP, the member firms of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte") and the relationship between audit and nonaudit services provided by Deloitte. Progress Energy, Inc. has adopted policies and procedures for approving all audit and permissible nonaudit services rendered by Deloitte, and the fees billed for those services. The Chief Accounting Officer is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. The Audit Committee specifically pre-approved the use of Deloitte for audit, audit-related, tax and nonaudit services, subject to the limitations of our pre-approved policy. Audit and audit-related services include assurance and related activities, assurance services associated with internal control over financial reporting, reports related to regulatory filings, 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 a detailed standing pre-approval whose project scope could not be defined at the time of standing approval that will involve an 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. Any approved projects with projected overruns must be communicated promptly to the Chief Accounting Officer for review and approval. Projected overruns that exceed Audit Committee project approvals by more than $50,000 must be approved by the Audit Committee separately from the original project.

The pre-approval policy requires management to obtain specific pre-approval from the Audit Committee for the use of Deloitte for any permissible nonaudit 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 nonaudit services will be considered for approval only in rare circumstances, which may include proposed services that provide significant economic or other benefits. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible nonaudit 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 nonaudit services at the time of the engagement must be brought to the attention of the Chief Accounting Officer for prompt submission to the Audit Committee for approval. These “de minimis” nonaudit 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 as it deems necessary and revise it accordingly.

Information regarding principal accountant fees and services is set forth respectively in Progress Energy’s and PEC’s definitive proxy statements for the 2006 Annual Meeting of Shareholders and incorporated by reference herein.

PEF

Set forth in the table below is certain information relating to the aggregate fees billed by Deloitte for professional services rendered to PEF for the fiscal years ended December 31.

	2005	2004
Audit fees	**$ 1,282,000**	$ 1,394,000
Audit-related fees	**18,000**	3,000
Tax fees	**179,000**	165,000
All other fees	–	1,000
Total	**$1,479,000**	$ 1,563,000

Audit fees include fees billed for services rendered in connection with (i) the audits of the annual financial statements of PEF (ii) the audit of management’s assessment of PEF’s internal control over financial reporting; (iii) the reviews of the financial statements included in the Quarterly Reports on Form 10-Q of PEF 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; (ii) special procedures and letter reports, (iii) benefit plan audits when fees are paid by PEF rather than directly by the plan; and (iv) accounting consultations for prospective transactions not arising directly from the audits.

Tax fees include fees billed for tax compliance matters and tax planning and advisory services.

All other fees include fees billed for rate case assistance and utility accounting training.

The Audit Committee has concluded that the provision of the nonaudit 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 AND FINANCIAL STATEMENT SCHEDULES

a) The following documents are filed as part of the report:

1. Financial Statements Filed:
   See ITEM 8 –Financial Statements and Supplementary Data

2. Financial Statement Schedules Filed:
   See ITEM 8 –Financial Statements and Supplementary Data

3. Exhibits Filed:
   See EXHIBIT INDEX

SIGNATURES

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

	PROGRESS ENERGY, INC.
	CAROLINA POWER & LIGHT COMPANY
Date: March 10, 2006	(Registrants)

By: /s/ Robert B. McGehee
Robert B. McGehee
Chairman and Chief Executive Officer
Progress Energy, Inc.
Chairman
Carolina Power & Light Company

By: /s/ Fred N. Day IV
Fred N. Day IV
President and Chief Executive Officer
Carolina Power & Light Company

By: /s/ Peter M. Scott III
Peter M. Scott III
Executive Vice President and Chief Financial Officer
Progress Energy, Inc.
Carolina Power & Light Company

By: /s/ Jeffrey M. Stone
Jeffrey M. Stone
Chief Accounting Officer and Controller
Progress Energy, Inc.
Chief Accounting Officer
Carolina Power & Light Company

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 and Director	March 10, 2006
/s/ Edwin B. Borden (Edwin B. Borden)	Director	March 10, 2006
/s/ James E. Bostic, Jr. (James E. Bostic, Jr.)	Director	March 10, 2006
/s/ David L. Burner (David L. Burner)	Director	March 10, 2006

/s/ Charles W. Coker (Charles W. Coker)	Director	March 10, 2006
/s/ Richard L. Daugherty (Richard L. Daugherty)	Director	March 10, 2006
/s/ W.D. Frederick, Jr. (W.D. Frederick, Jr.)	Director	March 10, 2006
/s/ W. Steven Jones (W. Steven Jones)	Director	March 10, 2006
/s/ William O. McCoy (William O. McCoy)	Director	March 10, 2006
/s/ E. Marie McKee (E. Marie McKee)	Director	March 10, 2006
/s/ John H. Mullin, III (John H. Mullin, III)	Director	March 10, 2006
/s/Peter S. Rummell (Peter S. Rummell)	Director	March 10, 2006
/s/ Carlos A. Saladrigas (Carlos A. Saladrigas)	Director	March 10, 2006
/s/ Theresa M. Stone (Theresa M. Stone)	Director	March 10, 2006
/s/ Jean Giles Wittner (Jean Giles Wittner)	Director	March 10, 2006

SIGNATURES

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

	FLORIDA POWER CORPORATION
Date: March 10, 2006	(Registrant)
	By: /s/ H. William Habermeyer, Jr. H. William Habermeyer, Jr. President and Chief Executive Officer
	By: /s/ Peter M. Scott III Peter M. Scott III Executive Vice President and Chief Financial Officer
	By: /s/ Jeffrey M. Stone Jeffrey M. Stone 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 and Director	March 10, 2006
/s/ H. William Habermeyer, Jr. (H. William Habermeyer, Jr.)	Director	March 10, 2006
/s/ Peter M. Scott III (Peter M. Scott III)	Director	March 10, 2006
/s/ Fred N. Day IV (Fred N. Day IV)	Director	March 10, 2006
/s/ William D. Johnson (William D. Johnson)	Director	March 10, 2006
/s/ Jeffrey J. Lyash (Jeffrey J. Lyash)	Director	March 10, 2006
/s/ John R. McArthur (John R. McArthur)	Director	March 10, 2006

EXHIBIT INDEX

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
*3a(1)	Restated Charter of Carolina Power & Light Company, as amended May 10, 1995 (filed as Exhibit No. 3(i) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1995, File No. 1-3382).		X	
*3a(2)	Restated Charter of Carolina Power & Light Company as amended on May 10, 1996 (filed as Exhibit No. 3(i) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997, File No. 1-3382).		X	
*3a(3)	Amended and Restated Articles of Incorporation of Progress Energy, Inc. (f/k/a CP&L Energy, Inc.), as amended and restated on June 15, 2000 (filed as Exhibit No. 3a(1) to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15929 and No. 1-3382).	X		
*3b(4)	Amended and Restated Articles of Incorporation of Progress Energy, Inc. (f/k/a CP&L Energy, Inc.), as amended and restated on December 4, 2000 (filed as Exhibit 3b(1) to Annual Report on Form 10-K for the year ended December 31, 2001, as filed with the SEC on March 28, 2002, File No. 1-15929).	X		
*3b(5)	By-Laws of Progress Energy, Inc., as amended on March 17, 2004 (filed as Exhibit No. 3(ii)(a) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, File No. 1-15929).	X		
*3b(6)	By-Laws of Carolina Power & Light Company, as amended on March 17, 2004 (filed as Exhibit No. 3(ii)(b) to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, File No. 1-3382 and 1-15929).		X	
*3b(7)	Amended Articles of Incorporation of Florida Power Corporation (filed as Exhibit 3(a) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 1991, as filed with the SEC on March 30, 1992, File No. 1-3274).			X
*3b(8)	Bylaws of Progress Energy Florida, as amended October 1, 2001 (filed as Exhibit 3.(d) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-8349 and 1-3274).			X
*4a(1)	Description of Preferred Stock and the rights of the holders thereof (as set forth in Article Fourth of the Restated Charter of Carolina Power & Light Company, as amended,		X	

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	and Sections 1-9, 15, 16, 22-27, and 31 of the By-Laws of Carolina Power & Light Company, as amended (filed as Exhibit 4(f), File No.33-25560).			
*4a(2)	Statement of Classification of Shares dated January 13, 1971, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $7.95 Series (filed as Exhibit 3(f), File No. 33-25560).		X	
*4a(3)	Statement of Classification of Shares dated September 7, 1972, relating to the authorization of, and establishing the series designation, dividend rate and redemption prices for Carolina Power & Light Company's Serial Preferred Stock, $7.72 Series (filed as Exhibit 3(g), File No. 33-25560).		X	
*4b(1)	Mortgage and Deed of Trust dated as of May 1, 1940 between Carolina Power & Light Company and The Bank of New York (formerly, Irving Trust Company) and Frederick G. Herbst (Douglas J. MacInnes, Successor), Trustees and the First through Fifth Supplemental Indentures thereto (Exhibit 2(b), File No. 2-64189); the Sixth through Sixty-sixth Supplemental Indentures (Exhibit 2(b)-5, File No. 2-16210; Exhibit 2(b)-6, File No. 2-16210; Exhibit 4(b)-8, File No. 2-19118; Exhibit 4(b)-2, File No. 2-22439; Exhibit 4(b)-2, File No. 2-24624; Exhibit 2(c), File No. 2-27297; Exhibit 2(c), File No. 2-30172; Exhibit 2(c), File No. 2-35694; Exhibit 2(c), File No. 2-37505; Exhibit 2(c), File No. 2-39002; Exhibit 2(c), File No. 2-41738; Exhibit 2(c), File No. 2-43439; Exhibit 2(c), File No. 2-47751; Exhibit 2(c), File No. 2-49347; Exhibit 2(c), File No. 2-53113; Exhibit 2(d), File No. 2-53113; Exhibit 2(c), File No. 2-59511; Exhibit 2(c), File No. 2-61611; Exhibit 2(d), File No. 2-64189; Exhibit 2(c), File No. 2-65514; Exhibits 2(c) and 2(d), File No. 2-66851; Exhibits 4(b)-1, 4(b)-2, and 4(b)-3, File No. 2-81299; Exhibits 4(c)-1 through 4(c)-8, File No. 2-95505; Exhibits 4(b) through 4(h), File No. 33-25560; Exhibits 4(b) and 4(c), File No. 33-33431; Exhibits 4(b) and 4(c), File No. 33-38298; Exhibits 4(h) and 4(i), File No. 33-42869; Exhibits 4(e)-(g), File No. 33-48607; Exhibits 4(e) and 4(f), File No. 33-55060; Exhibits 4(e) and 4(f), File No. 33-60014; Exhibits 4(a) and 4(b) to Post-Effective Amendment No. 1, File No. 33-38349; Exhibit 4(e), File No. 33-50597; Exhibit 4(e) and 4(f), File No. 33-57835; Exhibit to Current Report on Form 8-K dated August 28, 1997, File No. 1-3382; Form of Carolina Power & Light Company First Mortgage Bond, 6.80% Series Due August 15, 2007 filed as Exhibit 4 to Form 10-Q for the period ended September 30, 1998, File No. 1-3382; Exhibit 4(b), File No. 333-69237; and Exhibit 4(c) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382.); and the Sixty-eighth		X	

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	Supplemental Indenture (Exhibit No. 4(b) to Current Report on Form 8-K dated April 20, 2000, File No. 1-3382; and the Sixty-ninth Supplemental Indenture (Exhibit No. 4b(2) to Annual Report on Form 10-K dated March 29, 2001, File No. 1-3382); and the Seventieth Supplemental Indenture, (Exhibit 4b(3) to Annual Report on Form 10-K dated March 29, 2001, File No. 1-3382); and the Seventy-first Supplemental Indenture (Exhibit 4b(2) to Annual Report on Form 10-K dated March 28, 2002, File No. 1-3382 and 1-15929); and the Seventy-second Supplemental Indenture (Exhibit 4 to PEC Report on Form 8-K dated September 12, 2003, File No. 1-3382); and the Seventy-third Supplemental Indenture (Exhibit 4 to PEC Report on Form 8-K dated March 22, 2005, File No. 1-3382); and the Seventy-fourth Supplemental Indenture (Exhibit 4 to PEC Report on Form 8-K dated November 30, 2005, File No. 1-3382).			
*4b(2)	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
*4b(3)	Seventh Supplemental 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); and the Eighth Supplemental 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); and the Sixteenth Supplemental 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); and the Twenty-ninth Supplemental 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); and the Thirty-eighth Supplemental 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); and the Thirty-ninth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on July 23, 2001); and the Fortieth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 18, 2003); and the Forty-first Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K filed with the SEC on February 21, 2003); and the Forty-second Supplemental Indenture (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); and the Forty-third Supplemental Indenture (filed as Exhibit 4			X

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	to Current Report on Form 8-K filed with the SEC on November 21, 2003); and the Forty-fourth Supplemental Indenture (filed as Exhibit 4.(m) to the Progress Energy Florida Annual Report on Form 10-K dated March 16, 2005); and the Forty- fifth Supplemental Indenture (filed as Exhibit 4 to Current Report on Form 8-K, filed on May 16, 2005).			
*4b(4)	Indenture, dated as of December 7, 2005, between Progress Energy Florida, Inc. and J.P. Morgan Trust Company, National Association, as Trustee with respect to Senior Notes, (filed as Exhibit 4(a) to Current Report on Form 8-K dated December 13, 2005, File No. 1-3274).			X
*4b(5)	Indenture, dated as of March 1, 1995, between Carolina Power & Light Company and Bankers Trust Company, as Trustee, with respect to Unsecured Subordinated Debt Securities (filed as Exhibit No. 4(c) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).		X	
*4b(6)	Indenture, dated as of February 15, 2001, between Progress Energy, Inc. and Bank One Trust Company, N.A., as Trustee, with respect to Senior Notes (filed as Exhibit 4(a) to Form 8-K dated February 27, 2001, File No. 1-15929).	X		
*4c	Resolutions adopted by the Executive Committee of the Board of Directors at a meeting held on April 13, 1995, establishing the terms of the 8.55% Quarterly Income Capital Securities (Series A Subordinated Deferrable Interest Debentures) (filed as Exhibit 4(b) to Current Report on Form 8-K dated April 13, 1995, File No. 1-3382).		X	
*4d	Indenture (for Senior Notes), dated as of March 1, 1999 between Carolina Power & Light Company and The Bank of New York, as Trustee, (filed as Exhibit No. 4(a) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382), and the First and Second Supplemental Senior Note Indentures thereto (Exhibit No. 4(b) to Current Report on Form 8-K dated March 19, 1999, File No. 1-3382); Exhibit No. 4(a) to Current Report on Form 8-K dated April 20, 2000, File No. 1-3382).		X	
*4e	Indenture (For Debt Securities), dated as of October 28, 1999 between Carolina Power & Light Company and The Chase Manhattan Bank, as Trustee (filed as Exhibit 4(a) to Current Report on Form 8-K dated November 5, 1999, File No. 1-3382), (Exhibit 4(b) to Current Report on Form 8-K dated November 5, 1999, File No. 1-3382).		X	
*4f	Contingent Value Obligation Agreement, dated as of November 30, 2000, between CP&L Energy, Inc. and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to Current	X		

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	Report on Form 8-K dated December 12, 2000, File No. 1-3382).			
*10a(1)	Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency, amending letter dated February 18, 1982, and amendment dated February 24, 1982 (filed as Exhibit 10(a), File No. 33-25560).		X	
*10a(2)	Operating and Fuel Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency, amending letters dated August 21, 1981 and December 15, 1981, and amendment dated February 24, 1982 (filed as Exhibit 10(b), File No. 33-25560).		X	
*10a(3)	Power Coordination Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Municipal Power Agency Number 3 and Exhibits, together with resolution dated December 16, 1981 changing name to North Carolina Eastern Municipal Power Agency and amending letter dated January 29, 1982 (filed as Exhibit 10(c), File No. 33-25560).		X	
*10a(4)	Amendment dated December 16, 1982 to Purchase, Construction and Ownership Agreement dated July 30, 1981 between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency (filed as Exhibit 10(d), File No. 33-25560).		X	
*10a(5)	Agreement Regarding New Resources and Interim Capacity between Carolina Power & Light Company and North Carolina Eastern Municipal Power Agency dated October 13, 1987 (filed as Exhibit 10(e), File No. 33-25560).		X	
*10a(6)	Power Coordination Agreement – 1987A between North Carolina Eastern Municipal Power Agency and Carolina Power & Light Company for Contract Power From New Resources Period 1987-1993 dated October 13, 1987 (filed as Exhibit 10(f), File No. 33-25560).		X	
*10b(1)	Progress Energy, Inc. $1,130,000,000 5-Year Revolving Credit Agreement dated as of August 5, 2004 (filed as Exhibit 10(i) to Quarterly Report on Form 10-Q for the period ended June 30, 2004, File No. 1-15929).	X		
*10b(2)	Amendment, dated as of March 11, 2005, to the	X		

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	$1,130,000,000 5-Year Revolving Credit Agreement among Progress Energy, Inc. and certain lenders, dated August 5, 2004 (filed as Exhibit 10b(10) to Annual Report on Form 10-K dated March 16, 2005, File No. 1-15929).			
*10b(3)	PEF 5-Year $450,000,000 Credit Agreement, dated as of March 28, 2005 (filed as Exhibit 10(ii) to Current Report on Form 8-K filed April 1, 2005, File No. 1-3274).			X
*10b(4)	PEC 5-¼-Year $450,000,000 Credit Agreement dated as of March 28, 2005 (filed as Exhibit 10(i) to Current Report on Form 8-K filed April 1, 2005, File No. 1-3382).		X	
-+*10c(1)	Retirement Plan for Outside Directors (filed as Exhibit 10(i), File No. 33-25560).		X	
-+*10c(2)	Resolutions of the Board of Directors dated May 8, 1991, amending the PEC Directors Deferred Compensation Plan (filed as Exhibit 10(b), File No. 33-48607).	X	X	
+*10c(3)	Resolutions of Board of Directors dated July 9, 1997, amending the Deferred Compensation Plan for Key Management Employees of Carolina Power & Light Company.		X	
+*10c(4)	Florida Progress Supplemental Executive Retirement Plan, as amended and restated effective February 20, 1997 (filed as Exhibit 10.(e) to the Florida Progress Annual Report on Form 10-K for the year ended December 31, 1999, as filed with the SEC on March 30, 2000, File No. 1-3274).			X
+*10c(5)	Executive Optional Deferred Compensation Plan (filed as Exhibit 10.(c) to the Florida Progress Annual Report on Form 10-K for the year ended December 31, 1996 as filed with the SEC on March 27, 1997, File No. 1-8349 and 1-3274).			X
-+*10c(6)	Carolina Power & Light Company Restricted Stock Agreement, as approved January 7, 1998, pursuant to the Company's 1997 Equity Incentive Plan (filed as Exhibit No. 10 to Quarterly Report on Form 10-Q for the quarterly period ended March 31, 1998, File No. 1-3382.)	X	X	X
+*10c(7)	Management Incentive Compensation Plan of Florida Progress Corporation, as amended December 14, 1999 (filed as Exhibit 10.(a) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 1999, as filed with the SEC on March 30, 2000, File No. 1-8349 and 1-3274).			X
+*10c(8)	Progress Energy Florida Management Incentive Compensation Plan, effective January 1, 2001 (filed as			X

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	Exhibit 10b(25) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 2000, as filed with the SEC on March 28, 2001, File No. 1-8349 and 1-3274).			
+*10c(9)	1997 Equity Incentive Plan, Amended and Restated as of September 26, 2001 (filed as Exhibit 4.3 to Progress Energy Form S-8 dated September 27, 2001, File No. 1-3382).	X	X	X
-+*10c(10)	Performance Share Sub-Plan of the 1997 Equity Incentive Plan, as amended January 1, 2001 (filed as Exhibit 10c(11) to Annual Report on Form 10-K for the year ended December 31, 2001, as filed with the SEC on March 28, 2002, File No. 1-3382 and 1-15929).	X	X	X
+*10c(11)	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	X
+*10c(12)	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	X
+*10c(13)	2002 Progress Energy, Inc. Equity Incentive Plan, amended and restated July 10, 2002 (filed as Exhibit 10(vi) to Quarterly Report on Form 10-Q for the period ended September 30, 2002, File No. 1-3382 and 1-15929).	X	X	X
+*10c(14)	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 Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+*10c(15)	Broad-Based Performance Share Sub-Plan, Exhibit B to the 2002 Progress Energy, Inc. Equity Incentive Plan (effective January 1, 2005) (filed as Exhibit 10(c) to Quarterly Report on Form 10-Q for the period ended September 30, 2005, File No. 1-3382, 1-15929 and 1-3274).	X	X	X
+10c(16)	Executive and Key Manager Performance Share Sub Plan, Exhibit A to the 2002 Progress Energy, Inc. Equity Incentive Plan.	X	X	X
+*10c(17)	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	X
+*10c(18)	Progress Energy, Inc. Amended and Restated Management	X	X	X

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	Deferred Compensation Plan, Adopted as of January 1, 2000, as Revised and Restated, effective January 1, 2005 (filed as Exhibit 10c(11) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).			
+*10c(19)	Progress Energy, Inc. Management Change-in-Control Plan, Amended and Restated Effective as of January 1, 2005 (filed as Exhibit 10c(12) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+*10c(20)	Form of Deferred Compensation Plan for Directors--Method of Payment Agreement of Progress Energy, Inc., effective as of 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	X
+*10c(21)	Amended and Restated Progress Energy, Inc. Restoration Retirement Plan, effective as of January 1, 2005 (filed as Exhibit 10c(15) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+*10c(22)	Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc., amended, effective January 1, 2005 (filed as Exhibit 10c(16) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+*10c(23)	Amended Non-Employee Director Stock Unit Plan of Progress Energy, Inc. effective January 1, 2006 (filed as Exhibit 10 to Current Report on Form 8-K dated December 14, 2005, File No. 1-15929).	X	X	X
+*10c(24)	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 Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+*10c(25)	Agreement dated April 27, 1999 between Carolina Power & Light Company and Sherwood H. Smith, Jr. (filed as Exhibit 10b(32) to Annual Report on Form 10-K for the year ended December 31, 1999, as filed with the SEC on March 27, 2000, File No. 1-3382).		X	
+*10c(26)	Employment Agreement dated August 1, 2000 between CP&L Service Company LLC and Robert McGehee (filed as Exhibit 10(iv) to Quarterly Report on Form 10-Q for the	X		

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	period ended September 30, 2000, File No. 1-15929 and No. 1-3382).			
+*10c(27)	Form of Employment Agreement dated August 1, 2000 (i) between Carolina Power & Light Company and Don K. Davis; and (ii) between CP&L Service Company LLC and Peter M. Scott III (filed as Exhibit 10(v) to Quarterly Report on Form 10-Q for the period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X	X
+*10c(28)	Amendment, dated August 5, 2005, to Employment Agreement dated between Progress Energy Service Company, LLC and Peter M. Scott III (filed as Exhibit 10 to Quarterly Report on Form 10-Q for the period ended June 30, 2005, File No. 1-15929, 1-3382 and 1-3274).	X	X	X
+*10c(29)	Form of Employment Agreement dated August 1, 2000 between Carolina Power & Light Company and Fred Day IV, C.S. "Scotty" Hinnant and E. Michael Williams (filed as Exhibit 10(vi) to Quarterly Report on Form 10-Q for the period ended September 30, 2000, File No. 1-15929 and No. 1-3382).	X	X	
+*10c(30)	Employment Agreement dated November 30, 2000 between Carolina Power & Light Company, Florida Power Corporation and H. William Habermeyer, Jr. (filed as Exhibit 10.(b)(32) to the Progress Energy Florida Annual Report on Form 10-K for the year ended December 31, 2000, as filed with the SEC on March 28, 2001, File No. 1-8349 and 1-3274).	X		X
+*10c(31)	Form of Employment Agreement between (i) Progress Energy Service Company and John R. McArthur, effective January 2003; (ii) Progress Energy Florida, Inc. and Jeffrey J. Lyash, dated December 15, 2003 effective January 2003 and (iii) Progress Energy Carolinas, Inc. and Lloyd M. Yates, dated January 1, 2005 (filed as Exhibit 10c(27) to Annual Report on Form 10-K for the year ended December 31, 2002, as filed with the SEC on March 21, 2003, File No. 1-3382 and 1-15929).	X	X	X
+*10c(32)	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 year-ended December 31, 2003, as filed with the SEC on March 12, 2004, File No. 1-3382 and 1-15929).	X	X	X
+*10c(33)	General Release and Severance Agreement, dated November 14, 2005, between Geoffrey S. Chatas and Progress Energy Service Company, LLC (filed as Exhibit 99.1 to Current Report on Form 8-K as filed with the SEC			

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	on November 14, 2005, File No. 1-15929, 1-3382 and 1-3274).			
+*10c(34)	Agreement dated March 31, 2004 between Progress Energy, Inc. and William Cavanaugh III (filed as Exhibit 10c(28) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	
+*10c(35)	Employment Agreement dated January 1, 2005 between Progress Energy Carolinas, Inc. and William D. Johnson (filed as Exhibit 10c(29) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X	X	X
+10c(36)	Amendment, effective as of April 1, 2005, to the Amended Management Incentive Compensation Plan of Progress Energy, Inc.	X	X	X
+10c(37)	Amendment, effective as of April 1, 2005, to the Amended and Restated Progress Energy, Inc. Management Deferred Compensation Plan.	X	X	X
*10d(1)	Agreement dated November 18, 2004 between Winchester Production Company, Ltd., TGG Pipeline Ltd., Progress Energy, Inc. and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 10d(1) to Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 16, 2005, File No. 1-3382 and 1-15929).	X		X
*10d(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	X		X

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
	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.)			
*10d(3)	Agreement and Plan of Merger by and among Progress Rail Services Holdings Corp., PRSC Acquisition Corp., PMRC Acquisition Co., Progress Rail Services Corporation, Progress Metal Reclamation Company, Progress Fuels Corporation and Progress Energy, Inc. (with respect to Articles III, VI, VIII and IX) dated February 17, 2005 (filed as Exhibit 10(a) to Quarterly Report on Form 10-Q for the period ended September 30, 2005, File No. 1-15929, 1-3382 and 1-3274).	X		
12(a)	Computation of Ratio of Earnings to Fixed Charges.	X		
12(b)	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.		X	
12(c)	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Dividends Combined.			X
21	Subsidiaries of Progress Energy, Inc.	X		
23(a)	Consent of Deloitte & Touche LLP.	X		
23(b)	Consent of Deloitte & Touche LLP.		X	
23(c)	Consent of Deloitte & Touche LLP.			X
31(a)	302 Certification of Chief Executive Officer	X		
31(b)	302 Certification of Chief Financial Officer	X		
31(c)	302 Certification of Chief Executive Officer		X	
31(d)	302 Certification of Chief Financial Officer		X	
31(e)	302 Certification of Chief Executive Officer			X
31(f)	302 Certification of Chief Financial Officer			X
32(a)	906 Certification of Chief Executive Officer	X		
32(b)	906 Certification of Chief Financial Officer	X		

Number	Exhibit	Progress Energy, Inc.	PEC	PEF
32(c)	906 Certification of Chief Executive Officer		X	
32(d)	906 Certification of Chief Financial Officer		X	
32(e)	906 Certification of Chief Executive Officer			X
32(f)	906 Certification of Chief Financial Officer			X

* 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 from Carolina Power & Light Company to Progress Energy, Inc., effective August 1, 2000.

Exhibit No. 12(a)

PROGRESS ENERGY, INC.
Computation of Ratio of Earnings to Fixed Charges
For the Years Ended December 31

(dollars in millions)	**2005**	2004	2003	2002	2001
Earnings, as defined:					
Income from continuing operations before minority interest	**$ 701**	$ 712	$ 813	$ 590	$ 723
Fixed charges, as below	**680**	667	659	683	688
Amortization of capitalized interest	**2**	1	1	–	–
Preferred dividend requirements	**(7)**	(7)	(7)	(7)	(7)
Minority interest	**26**	17	(2)	(1)	(2)
Capitalized interest	**(4)**	(7)	(20)	(38)	–
Income taxes, as below	**(50)**	101	(121)	(154)	(71)
Total earnings, as defined	**$ 1,348**	$ 1,484	$ 1,323	$ 1,073	$ 1,331
Fixed Charges, as defined:					
Interest on long-term debt	**$ 619**	$ 580	$ 592	$ 577	$ 556
Other interest	**38**	61	42	80	112
Imputed interest factor in rentals – charged principally to operating expenses	**16**	19	18	19	13
Preferred dividend requirements of subsidiaries	**7**	7	7	7	7
Total fixed charges, as defined	**$ 680**	$ 667	$ 659	$ 683	$ 688
Income Taxes:					
Income tax expense (benefit)	**$ (45)**	$ 106	$ (113)	$ (146)	$ (63)
Included in AFUDC – deferred taxes in book depreciation	**(5)**	(5)	(8)	(8)	(8)
Total income taxes	**$ (50)**	$ 101	$ (121)	$ (154)	$ (71)
Ratio of Earnings to Fixed Charges	**1.98**	2.22	2.01	1.57	1.93

Exhibit No. 12 (b)

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
Computation of Ratio of Earnings to Fixed Charges and
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined
For the Years Ended December 31

(dollars in millions)		**2005**		2004		2003		2002		2001
Earnings, as defined:										
Income before cumulative effect of changes in accounting principles	**$**	**493**	$	461	$	504	$	431	$	364
Fixed charges, as below		**205**		201		206		224		264
Income taxes, as below		**234**		234		233		199		215
Total earnings, as defined	**$**	**932**	$	896	$	943	$	854	$	843
Fixed Charges, as defined:										
Interest on long-term debt	**$**	**191**	$	183	$	188	$	205	$	246
Other interest		**6**		11		11		12		11
Imputed interest factor in rentals – charged principally to operating expenses		**8**		7		7		7		7
Total fixed charges, as defined		**205**		201		206		224		264
Preferred dividends, as defined		**4**		5		4		4		5
Total fixed charges and preferred dividends combined	**$**	**209**	$	206	$	210	$	228	$	269
Income Taxes:										
Income tax expense	**$**	**239**	$	239	$	241	$	207	$	223
Included in AFUDC – deferred taxes in book depreciation		**(5)**		(5)		(8)		(8)		(8)
Total income taxes	**$**	**234**	$	234	$	233	$	199	$	215
Ratio of Earnings to Fixed Charges		**4.55**		4.45		4.59		3.81		3.19
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined		**4.46**		4.36		4.50		3.74		3.13

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.
Computation of Ratio of Earnings to Fixed Charges and
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined
For the Years Ended December 31

(dollars in millions)	**2005**	2004	2003	2002	2001
Earnings, as defined:					
Net income	**$ 260**	$ 335	$ 297	$ 325	$ 311
Fixed charges, as below	**138**	122	103	114	117
Income taxes, as below	**121**	174	147	163	183
Total earnings, as defined	**$ 519**	$ 631	$ 547	$ 602	$ 611
Fixed Charges, as defined:					
Interest on long-term debt	**$ 116**	$ 107	$ 103	$ 99	$ 100
Other interest	**18**	10	(6)	10	14
Imputed interest factor in rentals – charged principally to operating expenses	**4**	5	6	5	3
Total fixed charges, as defined	**138**	122	103	114	117
Preferred dividends, as defined	**2**	2	2	3	3
Total fixed charges and preferred dividends combined	**$ 140**	$ 124	$ 105	$ 117	$ 120
Ratio of Earnings to Fixed Charges	**3.76**	5.17	5.31	5.27	5.22
Ratio of Earnings to Fixed Charges and Preferred Dividends Combined	**3.71**	5.08	5.21	5.13	5.09

PROGRESS ENERGY, INC.

List of Subsidiaries

The following is a list of certain direct and indirect subsidiaries of Progress Energy, Inc., and their respective states of incorporation as of December 31, 2005:

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	North Carolina
Florida Progress Corporation	Florida
Florida Power Corporation d/b/a/ Progress Energy Florida, Inc.	Florida
Progress Capital Holdings, Inc.	Florida
Progress Telecommunications Corporation	Florida
Progress Telecom, LLC	Delaware
Progress Fuels Corporation	Florida
PV Holdings, Inc.	North Carolina
Progress Ventures, Inc. d/b/a Progress Energy Ventures, Inc.	North Carolina
Strategic Resource Solutions Corp.	North Carolina
Progress Energy Service Company, LLC	North Carolina

Exhibit No. 23(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 33−33520 on Form S−8, Post−Effective Amendment 1 to Registration Statement No. 33−38349 on Form S−3, Registration Statement No. 333−81278 on Form S−3, Registration Statement No. 333−81278−01 on Form S−3, Registration Statement No. 333−81278−02 on Form S−3, Registration Statement No. 333−81278−03 on Form S−3, Post−Effective Amendment 1 to Registration Statement No. 333−69738 on Form S−3, Registration Statement No. 333−70332 on Form S−8, Registration Statement No. 333−87274 on Form S−3, Post−Effective Amendment 1 to Registration Statement No. 333−47910 on Form S−3, Registration Statement No. 333−52328 on Form S−8, Post−Effective Amendment 1 to Registration Statement No. 333−89685 on Form S−8, Registration Statement No. 333−48164 on Form S−8, Registration Statement No. 333-114237 on Form S-3, Registration Statement No. 333-104951 on Form S-8 and Registration Statement No. 333-104952 on Form S-8 of our reports dated March 6, 2006, relating to the consolidated financial statements and consolidated financial statement schedule of Progress Energy, Inc. (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2005 and 2003) and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10−K of Progress Energy, Inc. for the year ended December 31, 2005.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

Exhibit No. 23(b)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333−126966 on Form S−3 of our reports dated March 6, 2006, relating to the consolidated financial statements and consolidated financial statement schedule of Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC) (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning the adoption of new accounting principles in 2005 and 2003), appearing in this Annual Report on Form 10−K of PEC for the year ended December 31, 2005.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006

Exhibit No. 23(c)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-126967 on Form S-3 of our reports dated March 6, 2006, 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 new accounting principles in 2005 and 2003) appearing in this Annual Report on Form 10−K of PEF for the year ended December 31, 2005.

/s/ Deloitte & Touche LLP

Raleigh, North Carolina
March 6, 2006